# Alternative Energy Review

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# ERRATA

## ALTERNATIVE ENERGY REVIEW

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| Page | Errata |
|---|---|
| 90 | Figure 3-10-12: "10kW" should read "10MW" |

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# Alternative Energy Review

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## 1. Purpose and Content of the Review

This review consolidates and updates information about electricity generation technologies which are considered to be alternatives to more conventional technologies. The six alternative technologies discussed in detail in this review are those which offer the greatest potential for application in Ontario by the year 2014.

The review contains descriptions, technical and economic assessments and environmental information for these technologies as well as forecasts of their potential use in Ontario. The review identifies factors which tend to enhance or to limit commercial application of these technologies in Ontario.

The review does not assess in detail those alternative technologies which may hold promise for commercial use in other jurisdictions but which are not well suited for use in Ontario because of uncontrollable factors including geographic and climatic differences or fuel availability.

## 2. Technologies Evaluated

Ontario Hydro monitors and assesses developments of many alternative electricity generation technologies. The corporation concentrates its efforts on those technologies which appear to offer the greatest potential for application in Ontario in the foreseeable future.

This review addresses the potential of solar energy, wind energy, fuel cells, biomass, peat, and municipal solid waste. In addition to those technologies, Ontario Hydro also monitors developments related to nuclear fusion, advanced nuclear fission, advanced fossil, other alternative and renewable technologies (e.g., tidal and wave power), novel cogeneration and energy storage.

Specific options of the six technologies addressed in this review were selected for economic evaluation. These options are listed in Figure ES-1.

## 3. Economic Assessment

Two measures, the cost/benefit ratio and the levelized unit energy cost (LUEC), are used to assess the economics of the selected options. Cost/benefit ratios are calculated for the solar, wind and municipal solid waste options. Levelized unit energy costs are calculated for the fuel cell, biomass and peat options.

*Figure ES-1: Specific Options Assessed*

| Technology | Option |
|---|---|
| Solar Photovoltaic | 2 kW Rooftop Residential<br>100 kW Rooftop Commercial/ Industrial |
| Wind Turbine | 10 kW Single Wind Turbine<br>20 x 350 kW Wind Farm |
| Fuel Cell | 200 kW Phosphoric Acid<br>10 MW Phosphoric Acid<br>200 kW Molten Carbonate<br>10 MW Molten Carbonate<br>200 kW Solid Oxide<br>10 MW Solid Oxide |
| Biomass | 15 MW Conventional Thermal<br>75 MW Conventional Thermal |
| Peat | 15 MW Conventional Thermal<br>75 MW Conventional Thermal |
| Municipal Solid Waste | 50 MW Conventional Thermal |

Cost/benefit ratios are obtained by dividing the present value of the costs (capital, operation, maintenance and administration, and fuelling, if any) of an option over its service life by the present value of the benefits (electrical energy and capacity) to the electricity system which that option would provide over its service life. The benefits are calculated using Ontario Hydro's forecast incremental system values of power and energy. Cost/benefit ratios of less than or equal to one signal an economic option. The LUEC is a single value, expressed in cents per kilowatt-hour, representative of the unit cost of electricity delivered by an option over its service life.

The cost estimates used in these evaluations are based on the most current information available to Ontario Hydro. For three of the six technologies (solar, wind and fuel cells), an effort is made to estimate not only current (1991) costs but also projected (year 2000) costs. These three technologies are emerging and it is considered that there is significant potential for cost reductions. Hence, projected costs may be significantly lower than current costs. Only current costs are estimated for the remaining three technologies (the burning of biomass, peat and municipal solid waste). These technology options utilize conventional and mature combustion technologies and it is considered that there is a lesser potential for significant cost reductions.

Figure ES-2 shows whether each option was assessed using current costs only, current and projected costs, or projected costs only. It also summarizes performance assumptions used in evaluating each of the selected options and shows the fuel or energy source for each option. Note that two fuel cell types, molten carbonate and solid oxide, are not evaluated using current costs. These technologies are yet to be demonstrated on a commercial scale.

Figure ES-3 shows estimated cost/benefit ratios for the solar and wind options. These cost/benefit ratios include a 10 percent preference premium for renewable options and the appropriate transmission and distribution credits. Figure ES-4 shows estimated levelized unit energy costs for the fuel cell, biomass and peat options. For these five technologies, three estimates are provided for each option assessed. The point estimates reflect Ontario Hydro's assessment of the cost/benefit ratios or levelized unit energy costs. The lower estimates result from a combination of assumptions which reflect high performance (high benefits) and low costs. The upper estimates result from a combination of assumptions which reflect low performance (low benefits) and high costs. The results indicate that the solar, wind, fuel cell, biomass and peat options assessed are not currently economic compared to conventional generation technologies for Ontario. This is indicated by cost/benefit ratios of greater than one for solar and wind options and levelized unit energy cost estimates higher than those of conventional base-loaded generation options for the fuel cell, biomass and peat options.

*Figure ES-2: Key Economic and Performance Assumptions Applied to the Selected Options*

| Option | Evaluated Using | | Useful Life Assumed (yrs) | Annual Capacity Factor Assumed (%) | Thermal Efficiency (%) | Fuel/Energy Source |
|---|---|---|---|---|---|---|
| | Current Costs | Projected Year 2000 Costs | | | | |
| **Photovoltaics** | | | | | | |
| 2 kW rooftop residential | YES | YES | 30 | 12 | N/A | Sunlight |
| 100 kW rooftop commercial/industrial | YES | YES | 30 | 12 | N/A | Sunlight |
| **Wind** | | | | | | |
| 10 kW Single Turbine | YES | YES | 25 | 22 | N/A | Wind |
| 20 x 350 kW Wind Farm | YES | YES | 25 | 22 | N/A | Wind |
| **Fuel Cells** | | | | | | |
| 200 kW Phosphoric Acid | YES | YES | 20 | 80 | 36.4 | Natural Gas |
| 200 kW Molten Carbonate | NO | YES | 20 | 80 | 49.1 | Natural Gas |
| 200 kW Solid Oxide | NO | YES | 20 | 80 | 41.7 | Natural Gas |
| 10 MW Phosphoric Acid | YES | YES | 30 | 80 | 41.4 | Natural Gas |
| 10 MW Molten Carbonate | NO | YES | 30 | 80 | 54.5 | Natural Gas |
| 10 MW Solid Oxide | NO | YES | 30 | 80 | 51.9 | Natural Gas |
| **Biomass** | | | | | | |
| 15 MW Conventional Thermal | YES | NO | 30 | 80 | 22.7 | Plantation Wood |
| 75 MW Conventional Thermal | YES | NO | 30 | 80 | 24.9 | Plantation Wood |
| **Peat** | | | | | | |
| 15 MW Conventional Thermal | YES | NO | 30 | 80 | 26.0 | Milled Peat |
| 75 MW Conventional Thermal | YES | NO | 30 | 80 | 26.5 | Milled Peat |
| **Municipal Solid Waste** | | | | | | |
| 50 MW Conventional Thermal | YES | NO | 30 | 80 | 19.9 | Municipal Refuse |

*Figure ES-3: Cost/Benefit Ratios – Solar and Wind Options*

| | Using Current Costs | | | Using Projected Year 2000 Costs | | |
|---|---|---|---|---|---|---|
| | Cost/Benefit Ratio | | | Cost/Benefit Ratio | | |
| Option | Lower Estimate | Point Estimate | Upper Estimate | Lower Estimate | Point Estimate | Upper Estimate |
| **Photovoltaics** | | | | | | |
| 2 kW Rooftop Residential | 4.5 | 7.7 | 18.6 | 1.6 | 2.4 | 6.3 |
| 100 kW Rooftop Commercial/Industrial | 4.0 | 6.7 | 15.7 | 1.4 | 2.1 | 5.4 |
| **Wind** | | | | | | |
| 10 kW Single Wind Turbine | 1.1 | 1.7 | 4.0 | 1.1 | 1.5 | 3.7 |
| 20 x 350 kW Wind Farm | 1.1 | 1.6 | 3.3 | 1.1 | 1.5 | 3.2 |

*Figure ES-4: Levelized Unit Energy Cost Estimates – Fuel Cell, Biomass and Peat Options*

| | LUEC (¢/kWh) at 80% ACF | | | LUEC (¢/kWh) at 80% ACF | | |
|---|---|---|---|---|---|---|
| | Using Current Costs | | | Using Projected Year 2000 Costs | | |
| Option | Lower Estimate | Point Estimate | Upper Estimate | Lower Estimate | Point Estimate | Upper Estimate |
| **Fuel Cells** | | | | | | |
| 200 kW Phosphoric Acid | 10.8 | 14.1 | 19.4 | 8.4 | 10.2 | 14.1 |
| 200 kW Molten Carbonate | N/A | N/A | N/A | 7.0 | 8.5 | 12.6 |
| 200 kW Solid Oxide | N/A | N/A | N/A | 8.0 | 9.8 | 14.6 |
| 10 MW Phosphoric Acid | 8.9 | 11.6 | 15.1 | 6.4 | 7.5 | 9.6 |
| 10 MW Molten Carbonate | N/A | N/A | N/A | 5.7 | 6.9 | 9.8 |
| 10 MW Solid Oxide | N/A | N/A | N/A | 6.1 | 7.4 | 10.5 |
| **Biomass** | | | | | | |
| 15 MW Conventional Thermal | 9.6 | 13.7 | 21.4 | N/A | N/A | N/A |
| 75 MW Conventional Thermal | 6.3 | 9.5 | 14.7 | N/A | N/A | N/A |
| **Peat** | | | | | | |
| 15 MW Conventional Thermal | 14.5 | 19.5 | 29.0 | N/A | N/A | N/A |
| 75 MW Conventional Thermal | 9.4 | 12.2 | 17.2 | N/A | N/A | N/A |
| Typical LUEC for Conventional (Base-loaded) Generation Options* at 80% ACF | 3 to 5 | | | N/A | | |

* For example nuclear and conventional steam cycle coal.
N/A = Not Applicable.

The cost of plants which burn municipal solid waste (MSW) should be viewed in light of their contribution towards the avoidance of waste disposal costs. The "tipping fees" paid to an operator of an MSW incineration plant to receive the waste provide substantial revenue. Electricity, if produced, is a byproduct of MSW incineration. The benefits associated with the operation of the plant are a combination of the revenues provided by the tipping fees and the revenues from the sale of electricity. Figure ES-5 shows cost/benefit ratios at various tipping fees. Given that current tipping fees in the Metropolitan Toronto area are in the order of $150 per tonne, these values indicate that the incineration of MSW could be an economical method of producing electricity. However, the installation of new MSW incineration facilities is prohibited in Ontario.

***Figure ES-5: Municipal Solid Waste Option – Cost/Benefit Ratios at Various Tipping Fees***

| Option – 50 MW Municipal Solid Waste Plant | | | | |
|---|---|---|---|---|
| Tipping Fees (per tonne) | $150 | $60 | $30 | $17.39 |
| Cost/BenefitRatio (Using Current Costs) | 0.3 | 0.5 | 0.7 | 1.0 |

The fuel cell, biomass, peat and municipal solid waste options may be well suited to cogeneration applications, producing both electricity and useable heat. The heat can be used on-site in an industrial or commercial application which would make these options more attractive to non-utility generators. The heat may also be sold, for example for district heating. The potential economic benefit derived from the use of or sale of the heat has not been included in the above economic assessments. The magnitude of the potential benefits depends on the amount of useable heat produced and on assumptions made about the value of the heat. Note that options with high fuel-to-electricity conversion efficiencies will have correspondingly lower amounts of useable heat available for cogeneration applications. If it is assumed that the cogeneration application is optimal such that about 80 percent of the energy content of the fuel is recovered as useable heat or electricity and that the heat is valued at the commercial/industrial price of natural gas, then the value of the heat could result in a lifetime levelized unit energy benefit of zero to 6 ¢/kWh, depending on the additional costs incurred for the installation and operation of heat recovery and distribution equipment.

## 4. Technology Descriptions and Assessments

### *Solar*

Solar energy is essentially an unlimited resource. While the amount of sunlight varies from day to day and season to season, the solar energy falling on Ontario in a year is much greater than the province's total energy, or electricity, demand. Solar energy is, however, a dispersed energy resource, a factor which tends to increase the cost of its collection.

The quality and quantity of sunlight determine that photovoltaic rather than solar thermal-electric technology is the solar energy technology more suited for the generation of electricity in Ontario. Photovoltaic cells are made of semi-conducting materials which produce direct current electricity when exposed to sunlight; that is, without an intermediate heating stage. Photovoltaics are developing rapidly and technological breakthroughs may occur that will significantly reduce the cost of manufacturing photovoltaic cells.

Photovoltaic technology is well established and used widely throughout the world. World capacity is approximately 200 MW. Photovoltaic systems suitable for residential use can be purchased from local retailers in many parts of North America, Europe, and elsewhere. Most applications are found where there is no cost-effective access to an electricity grid or other sources of electricity. Remote cottage applications account for a rapidly growing market.

Canada's photovoltaic installations total about 500 kW. The Canadian Coast Guard is the largest user with some 3000 installations ranging from 10 to 1200 watts, powering lighthouses, radio beacons and other navigational devices. Units up to 2 kW are used by rail and telecommunication companies to power remote radio repeater stations.

Although photovoltaic technology is a proven source of decentralized generation it is currently uneconomic as a source of electricity for Ontario's bulk electricity system. Current costs are high; however, significant cost reductions are forecast to occur by the year 2000.

The advantages of photovoltaic technology include:

- use of a renewable energy source,
- high social acceptance,
- no fuel costs,
- low maintenance costs,
- modularity, and

- minimal environmental impact, assuming roof-mounted installation.

Barriers to large-scale implementation of photovoltaic technology include:

- high initial capital costs,
- intermittent availability of power, and
- limited manufacturing capacity at present.

Use of solar technology is expected to continue in niche applications and in remote installations where grid electricity is not readily available. Early on-grid applications will likely be in the form of dispersed generation at sites where there is a good match between the availability of solar energy and the need for electricity.

The potential contribution of photovoltaic technology to Ontario's supply mix could be as little as 1 MW by the year 2005 or as much as 100 MW by the year 2014 depending upon cost and technological developments.

### *Wind*

Wind is a renewable, but intermittent, energy source which may vary greatly over short periods of time. Ontario is not considered to be a windy area since average speeds range from less than 10 km/h to about 20 km/h. Wind speeds are, however, influenced by local topography and ground cover, as well as height above ground, and are therefore very site specific.

Devices used to convert the wind's energy into electricity are called wind energy conversions systems (WECS). They range in nominal capacity from about 50 watts (for battery charging applications) to about 300 to 600 kW (for use in utility applications). WECS connected to electrical grids have ranged in size from 1 kW to 4000 kW.

Wind power is a proven technology which has advanced greatly over the last decade. In 1990 there were approximately 2000 MW of wind energy capacity installed around the world. That capacity is located mainly in California (14,000 turbines, 1350 MW) and Denmark (2400 turbines, 200 MW). Wind energy supplies about 1 percent of California's electricity and about 2 percent of Denmark's.

Wind power technologies have made steady progress in the areas of increased reliability, reduced cost, and the ability to operate at low wind speeds. This steady progress is expected to continue.

Cost estimates in this review indicate that wind power is not currently economic for the production of electricity for Ontario's bulk electricity system. Wind power will likely be applied in niche applications involving off-grid hybrid systems (e.g., wind/diesel) where the cost of the displaced generation is high. Ontario's first on-grid applications will likely be in the form of dispersed non-utility generation (i.e., single wind turbines or wind farms).

The advantages of wind energy include:

- use of a renewable energy source,
- no fuel costs,
- no pollutant emissions,
- minimal waste products,
- modularity, and
- social acceptance has generally been high in other jurisdictions.

Barriers to large-scale wind development include:

- limited number of good wind sites in Ontario,
- intermittent availability of power, and
- the amount of land potentially required for large wind farms.

The potential contribution of wind generation is difficult to estimate because of the site specific nature of the technology. Some of the most promising areas for wind-powered generation are Pelee Island, the Bruce area of Lake Huron and the Sudbury area.

The potential contribution of wind power to Ontario's electricity supply mix could be as little as 1 MW by the year 2005 or as high as 40 MW by the year 2014 depending upon costs and technological developments.

### *Fuel Cells*

Fuel cells convert the chemical energy of a fuel (ideally pure hydrogen) into direct current electricity by means of an electrochemical reaction. An oxidant (ideally pure oxygen) is also required to complete the reaction. There are five principal fuel cell types which have been or are currently being developed. All these fuel cells currently being developed rely ultimately on hydrogen, or a mixture of hydrogen and carbon monoxide as the principal fuel, and oxygen from the air as the oxidant. Natural gas is the present fuel of choice as the source for the hydrogen or hydrogen and carbon monoxide mixture, although other fuels can be used.

The U.S. is acknowledged to be the leader in fuel cell research; however, work is also under way in Japan, the European Community, Canada, and elsewhere. Interest in fuel cells as utility power plants results mainly from their high efficiency at full and part loads, their low pollutant emissions and noise, their modularity, and their ease of siting. Other features include load following ability, and in some cases the ability to supply additional power for peaking at slightly reduced overall fuel efficiency. Some fuel cell technologies have the potential to produce both electricity and useable heat in cogeneration applications. When fuelled with pure hydrogen, fuel cells produce only electricity, water and heat. When other fuels are used (e.g., natural gas) emissions such as carbon dioxide, nitrogen oxides, carbon monoxide, sulphur dioxide and particulates may be produced. However a lesser quantity of these emissions is produced per unit of electricity because of the higher efficiency of fuel cells. Because of the nature of operation of fuel cells, only trace amounts of nitrogen oxides and sulphur dioxide are produced.

Fuel cell technology is developing rapidly. Some fuel cell technologies are well developed for niche applications such as space programs in which size, weight and efficiency are more important than cost. Of the three major fuel cell types assessed in the review only one (phosphoric acid) can be considered to be commercially available. A second (molten carbonate) may be commercially available by the year 2000 and the third (solid oxide) sometime after the year 2000. Development will continue because of the advantages of fuel cells over conventional fossil fuel technologies (higher efficiencies, modularity, lower noise and lower emissions). The useable heat makes fuel cells attractive in cogeneration applications.

Implementation of fuel cells will be constrained by capital cost, fuel cost and demonstration of reliable operation. A major challenge is to demonstrate reliable operation of fuel cell power plants for tens of thousands of hours. Cost estimates indicate that fuel cell power plants are not currently economic for the production of electricity for Ontario's bulk electricity system if the plants are used for power production only. Fuel cell power plants will likely first become cost-effective in combined heat and power applications where the value of the useable heat produced could partially offset electricity production costs.

Fuel cells are dispatchable and can be operated to meet base, intermediate or peak loads.

The advantages of fuel cell technology include:

- high energy conversion efficiency,
- siting flexibility,
- modularity, and
- low emission levels.

Barriers to large-scale implementation of fuel cell technology include:

- high capital costs, and
- limited experience with the technology.

The potential contribution of fuel cells to Ontario's electricity supply mix could be as little as 1 MW by the year 2005 or as high as 800 MW by the year 2014 depending upon costs and technological developments.

### *Biomass*

Biomass fuels considered in this review are waste wood and wood from plantations and from natural forests. Biomass is a dispersed resource which can be found or grown in large parts of Ontario. Fast-growing hybrid poplar and willow are the plantation-grown fuels considered in this review.

Interest in biomass-fuelled generation has increased recently because of its potential for use as a renewable resource when properly managed. Furthermore, properly managed biomass plantations would be carbon dioxide neutral except to the extent that fossil fuels would be burned to cultivate and transport wood.

Cost is the major factor limiting the replacement of fossil fuels by biomass. Biomass has a lower energy density and higher moisture content than fossil fuels; biomass-fuelled plants are therefore larger and of higher capital cost per unit of capacity than fossil-fuelled plants. Biomass-fired plants also tend to be "mine-mouth" operations because the large volume and low energy density of the fuel makes it expensive to transport to distant generating stations.

Currently biomass-fuelled power plants rely on well established combustion technologies which perform at around 20 to 25 percent thermal efficiency. Research is being conducted toward the development of biomass-fuelled integrated gasification combined cycle (IGCC) systems. If successful such systems would increase the fuel utilization efficiency and reduce the capital costs of biomass-fuelled electrical generation. Ongoing research in several countries, including Canada, aims at developing biomass species suitable for energy plantations. Success in this area could lead to reduced costs for biomass fuels for electrical generation.

Biomass-fired generating plants exist in the U.S., Sweden, the U.K., Canada and other countries. Industries in Ontario (particularly pulp and paper and timber and wood working) fire wood waste for generation of process steam and some use their in-house waste for cogeneration of electricity. The installed capacity of those plants totals about 180 MW. They burn wood or wood in combination with other fuels. Other plants are planned or under construction. There are no generating stations in Ontario fired primarily by plantation-grown biomass.

Cost estimates indicate that plantation biomass-fuelled power plants are not currently economic for the production of electricity for Ontario's bulk electricity system if the plants are used for electricity production only. Biomass power plants can be economical for electricity generation when fuelled with waste biomass if the fuel is available free of charge or at negative cost.

Biomass-fired generating stations are dispatchable and can be operated to meet base and/or intermediate loads.

The advantages of biomass as a fuel for electricity generation include:

- renewable resource, when properly managed,
- lower emissions of sulphur dioxide than fossil-fuelled generation,
- potential to be carbon dioxide neutral, and
- low in ash and the ash could be returned to the forest or plantation.

The current barriers to wide-scale introduction of biomass-fuelled electricity generation in Ontario include:

- high capital cost of the plant,
- limited supplies of biomass waste,
- anticipated high cost of plantation-grown fuel production and transportation,
- significant land requirements for the plantations, and
- relatively low thermal efficiencies of existing biomass combustion technologies.

The potential contribution of biomass is determined largely by the availability of low cost fuel. The contribution of biomass-fuelled power plants to Ontario's bulk electricity supply in addition to capacity already installed, could be as much as 100 MW by the year 2005 if only waste biomass is used, and could include a further 100 MW by the year 2014 if plantation biomass becomes viable and costs decline.

### *Peat*

Peat is dead vegetation such as grass and moss which has been accumulating in bogs, a few millimetres each year, since the last ice age. In its natural state it contains both free and bound water averaging about 90 percent moisture content in total.

Peat is of interest as a fuel for electricity generation in Ontario mainly because it is a significant indigenous resource. Ontario's peat deposits are located primarily in the northern and southeastern parts of the province and they cover some 16 million hectares. If less than 2 percent of those peat resources were used they could potentially support about 5000 MW of generating capacity for 30 years.

Peat has been used extensively as a fuel for electricity generation in Ireland and Finland, often co-fired with other fuels such as wood and coal, but has not been applied in North America. There are also reported to be significant generating facilities in the U.S.S.R.; however, details are unavailable. Milled (dry-mined) peat, the most common form of the fuel, can be extracted using conventional farming equipment.

Cost is a major factor limiting the replacement of fossil fuels by peat. Peat is more costly than oil, gas and coal because of its lower energy density and high moisture content. Peat-fuelled plants are physically larger, and of higher capital cost than fossil-fuelled plants per unit of capacity. Peat-fired plants, like biomass-fired plants, tend to be located close to the fuel source because of the high transportation costs associated with the large volume and low energy density of the fuel.

Cost estimates in this review indicate that peat-fuelled power plants are not currently economic for the production of electricity for Ontario's bulk electricity system. The use of peat-fuelled power plants in combined heat and power applications would make these plants more economical.

If Ontario's peat resources are to be developed wet mining techniques may prove more cost-effective for Ontario's small, separated bogs and climatic conditions. Those techniques will require specialized equipment and involve considerable research and development effort. Development of this resource would likely have to address environmental issues including disruption of the peat bog ecology. Traditional harvesting of peat for horticultural and fuel uses is accepted practice in a number of countries.

Research continues into cost-effective production of peat fuels, peatland reclamation, and the development of peat-fuelled integrated gasification combined cycle (IGCC) systems.

Peat-fired generating stations are dispatchable and can be operated to meet base and intermediate loads.

Advantages of peat as a fuel for electricity generation in Ontario include:

- indigenous fuel, and
- low sulphur dioxide emissions.

Barriers to wide-scale introduction of peat-fuelled generation in Ontario include:

- high cost of fuel production and transportation,
- high capital cost of the generating plant, and
- possible environmental concerns about peat extraction and fuel preparation, $CO_2$ emissions and non-renewability.

Cost considerations make it unlikely that large amounts of peat-fired generation would be implemented by the year 2014. Peat fuel may be co-fired with coal if an economic peat fuel can be provided. The potential contribution of peat-fuelled power plants to Ontario's electricity supply mix could be in the order of 20 MW by the year 2005 and as high as 100 MW by the year 2014.

***Municipal Solid Waste (MSW)***

The incineration of municipal solid waste is common in various parts of the world. Electricity, if produced, is a byproduct of the incineration process. Electricity may also be produced by burning landfill gas which would otherwise be flared for safety and environmental reasons.

Municipal solid waste fuel is a limited resource which can be consumed at more or less the rate at which it is produced. Energy-from-waste facilities tend to be close to larger population centres where the waste is produced and where there is a demand for electricity and heat. The generating plant is usually tied into the electrical grid. There is little potential for energy-from-waste in off-grid applications.

The generation of electricity from MSW fuels using conventional combustion technologies is proven and well understood. Emission control technology is available or being developed to meet increasingly stringent regulations. "Landfill gas" technologies burn the gases produced by anaerobic decomposition of MSW. "Mass burn" technologies involve incineration of untreated and largely unseparated MSW. "Refuse derived fuel" (RDF) results from the processing of MSW into uniform and easily handled combustible material. Typically RDF is a byproduct of processes which recover reusable and recyclable materials from municipal waste.

Generators burning landfill gas had been installed in some 20 countries by 1989 and range in size from 1 MW to about 25 MW. Ontario's first plant, rated at about 22 MW, is being commissioned near Pickering. Other Toronto-area plants are being proposed and evaluated.

Mass burning is the most common method of energy recovery from waste. American, European and Japanese companies operated more than 500 mass burn facilities in 1989 and more are planned or under construction. Many municipalities in Europe and Japan burn waste to produce electricity and steam for district heating of apartment buildings, commercial buildings, hospitals, special industries, swimming pools, greenhouses, and other commercial or industrial uses.

RDF combustion dates back to 1886 in Hamburg, Germany. One source lists 39 such plants in the U.S. with design capacities greater than 180 tonnes per day. The largest U.S. plant, located in Miami, consumes 3000 tonnes per day and produces 75 MW.

From a purely cost perspective the burning of MSW would be an economical method of generating electricity in Ontario given the tipping fees in force in the Greater Toronto Area. The use of such plants in combined heat and power applications would make them more economical. RDF costs would be higher than those associated with mass burn plants, and they would yield less electricity because of their higher station service requirements.

Advantages of MSW as a fuel for electricity generation include:

- the renewable and indigenous nature of the fuel,
- reduction of waste volume, and
- use of an otherwise wasted resource.

Barriers to wide-scale introduction of MSW-fuelled energy recovery systems in Ontario include:

- limited resource,
- lack of public acceptance,
- government policy, and
- low tipping fees outside the Greater Toronto Area.

The potential generation of electric power from Ontario's existing landfill gas sites is estimated to be 30 MW. That potential is expected to increase to 60 to 70 MW by the year 2005 unless mass burn facilities are approved, thereby reducing landfill gas supplies.

The potential contribution of MSW mass-burn generation is limited by the availability of municipal waste and concerns about the environmental impacts of incineration. Several incineration plants are operated in Ontario; however, in 1991 the Ontario government stated that it will not approve new MSW incineration facilities.

Assuming that 50 percent of garbage is recycled, currently it would be possible to generate up to 145 MW by mass burning refuse from the Greater Toronto Area. Assuming provincial government approval, and some increase in the total amount of garbage production, that capacity could increase to about 200 MW by the year 2014.

Figure ES-6 summarizes information about current and predicted technological development and uses of the six technologies.

## 5. Environmental Considerations

Environmental effects associated with fuel extraction and processing, construction, operations and maintenance and decommissioning were considered. In the case of technologies which would require the purchase of prefabricated items, the management of environmental effects associated with fabrication are assumed to be included in the price of the items and are not addressed in detail.

Figure ES-7 summarizes environmental considerations associated with each of the six technologies.

Wind and solar electricity generation use a renewable resource which is consistent with the principles of sustainability. The sustainability of biomass plantations would depend on the time period over which an area of land could continuously support the plantation and on the extent to which fossil fuels would be burned to cultivate and transport wood. The sustainability of fuel cells would depend on the choice of fuel.

Atmospheric emissions, aquatic effluents, and waste management are issues associated with conventional combustion technologies, and would apply to peat, biomass and MSW-fuelled electricity generation. MSW mass burn technology in particular may require stringent controls and waste management practices to control emissions of toxins, heavy metals and acid gases.

Land requirements are important considerations for biomass plantations, peat, centralized photovoltaics and wind farms. Decentralized photovoltaic applications on rooftops would alleviate land use concerns.

Properly managed biomass plantations would be carbon dioxide neutral except to the extent that fossil fuels would be burned to cultivate and transport wood. Centralized photovoltaic and wind applications would not contribute to global warming except to the extent that forests (a carbon sink) were cleared. Because of their higher efficiency, fuel cells fuelled by natural gas would produce less carbon dioxide emissions per unit of electricity than would conventional generation technologies.

Decentralized photovoltaic, wind turbine, or fuel cell installations would likely produce limited regional employment and development, and would create minimal adverse community impacts. Centralized peat and biomass generating facilities might stimulate the economy in northern or eastern Ontario communities, but the potential exists for significant localized community impacts. MSW facilities would likely be situated near populated areas and care would have to be taken to obviate concerns regarding traffic, odours and noise. The provincial government has stated that it will not approve new MSW incineration facilities in Ontario.

*Figure ES-6: Current and Predicted Technological Development and Uses*

| Technology | Current | Predicted by Year 2000 | Predicted by Year 2014 |
|---|---|---|---|
| Photovoltaics | • Silicon technology established.<br>• Niche applications and demonstration projects.<br>• Hybrid systems at remote sites.<br>• Uneconomic compared to conventional generation in Ontario for grid electricity. | • Technological breakthroughs and manufacturing economies of scale could lower costs.<br>• Remote site (off-grid) applications.<br>• Load displacement applications (on-grid) may begin to appear if costs low enough.<br>• Likely still uneconomic compared to conventional generation. | • Further technological breakthroughs possible. Incorporation in building materials could lead to increased use. |
| Wind | • Advanced variable wind speed turbines under development to lower energy costs.<br>• Market penetration limited because of intermittent availability of power.<br>• Uneconomic compared to conventional generation in Ontario for grid electricity. | • Advanced variable wind speed turbines could be increasingly cost competitive.<br>• Market penetration limited because of intermittent availability of power.<br>• Likely still marginally less economic than conventional generation. | • Further technological advances could lead to increased viability at sites of moderate wind speed.<br>• Economies of scale could lower costs. |
| Fuel Cells | • PAFC close to being commercial.<br>• Uneconomic compared to conventional generation in Ontario for grid electricity.<br>• PAFC demonstration projects being constructed.<br>• Small-scale demonstration projects for MCFC and SOFC. | • PAFC likely established. MCFC likely commercial. SOFC in advanced demonstration phase.<br>• Small fuel cells fuelled by natural gas likely for dispersed cogeneration and/or utility applications.<br>• Utility scale technologies in development and demonstration stage.<br>• Likely still uneconomic compared to conventional generation. | • MCFC likely established. SOFC likely commercial.<br>• Small fuel cells fuelled by natural gas likely for dispersed cogeneration and/or utility applications.<br>• Fuel cells or IGCC could emerge as the preferred option for coal-fuelled generation.<br>• Economics uncertain. |
| Biomass | • Conventional combustion technology proven.<br>• Waste biomass plants economic and in use in cogeneration applications in Ontario.<br>• Limited by fuel availability.<br>• Plantation options in assessment stage and not economic. | • High efficiency generation technologies may be available.<br>• Plantation techniques may be proven.<br>• Generation subject to cost-effective fuel availability. | • High efficiency generation technologies may be available.<br>• Generation subject to cost-effective fuel availability.<br>• May become a viable generation option driven by concerns about $CO_2$ emissions. |
| Peat | • Technology proven. Used extensively in Ireland and Finland because of high costs of imported fuels.<br>• Uneconomic in Ontario compared to conventional generation options. | • Implementation on a significant scale in Ontario unlikely because of high costs.<br>• Possible demonstration of advanced peat-fuelled production and peat IGCC technologies. | • High efficiency generation technologies may be available.<br>• Generation subject to cost-effective fuel availability. |
| Municipal Solid Waste | • Technology proven. Small mass burn and RDF plants operating in Hamilton and London.<br>• Landfill gas plant being commissioned.<br>• Government policies prohibit further mass burn plants. | • Landfill gas operations continue.<br>• Mass burn not significantly used because of environmental concerns and government policies.<br>• Capacity limited by available fuel resource. | • Likely unchanged. Depends on success of waste reduction, reuse, recycling initiatives.<br>• Capacity limited by available fuel resource. |

*Figure ES-7: Summary of Environmental Considerations for Alternative Energy Technologies*

| Option | Environmental Consideration | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Air Emissions | Land Use | Aquatic Effluents | Aesthetics | Solid Waste | Non-Renewable Energy Source | Local Socio-economic impacts | Other |
| Photovoltaics: Centralized | | ▲ | | ▲ | ▲[4] | | ▲ | PV Manufacture |
| Photovoltaics: Decentralized | | | | | ▲[4] | | | PV Manufacture |
| Wind: Centralized | | ▲ | | ▲ | ▲[4] | | ▲ | |
| Wind: Decentralized | | | | | ▲[4] | | | |
| Fuel Cells | ▲[1] | | ▲[3] | | ▲ | ▲[2] | | Emissions lower than for fossil stations[1] |
| Biomass: Plantation | ▲ | ▲ | ▲ | | ▲ | | ▲ | Plantation sustainability unknown |
| Biomass: Wood Waste | ▲ | | ▲ | | ▲ | | | |
| Peat | ▲ | ▲ | ▲ | | ▲ | ▲ | ▲ | Peatland disruption |
| MSW: Landfill Gas | ▲ | | ▲[5] | | | ▲ | | |
| MSW: Mass Burn/RDF | ▲ | | ▲ | | ▲ | | ▲ | Public/ government acceptability |

**Notes:** 1 – Emissions are fuel dependent. Hydrogen fuel results in electricity, water and heat.
2 – Renewability is fuel dependent.
3 – Fuel cell combined cycle applications would require cooling water.
4 – Primarily during decommissioning. Recycling/reuse opportunities would exist.
5 – If steam electric system is used.

## 6. Potential Contribution of the Technologies

As discussed in Section 4, the potential contribution of the six alternative energy technologies assessed in this review to Ontario's electricity supply mix is influenced by many factors including costs, government policies, societal values, technological development and industrial production capability. Figure ES-8 identifies the potential contribution of the six alternative energy technologies under three scenarios assessed in this review. The descriptions of these three scenarios are outlined in Figure ES-8. The amounts identified are in addition to Ontario's existing solar, wind, biomass and MSW capacity.

Figure ES-9 compares the potential contribution under Scenarios 1 and 2 of this assessment with the results of a previous assessment prepared by Ontario Hydro in 1986 (Demand/Supply Options Study) and, for biomass and municipal solid waste, those of a more recent assessment contained in Ontario Hydro's 1990 Non-Utility Generation Plan.

*Figure ES-8: Potential Contribution of Alternative Energy Technologies Under Various Scenarios*

| Technology | Potential by Year 2005 (MW) | | Potential by Year 2014 (MW) |
|---|---|---|---|
| | Scenario 1 | Scenario 2 | Scenario 3 |
| Photovoltaics | < 1 | < 1 | 50 – 100 |
| Wind | < 1 | < 1 | 10 – 40 |
| Fuel Cells | < 1 | < 10 | 300 – 800 |
| Biomass | | | |
| (1) Waste | 100 | 100 | 100 |
| (2) Plantation/Forest | Nil | 20 | 50 – 100 |
| Peat | Insignificant | 20 | 50 – 100 |
| Municipal Solid Waste | | | |
| (1) Landfill gas | 60 – 70 | 60 – 70 | 25* |
| (2) Mass Burn | < 15 | < 15 | 100 – 200 |
| **Totals (Approximate)** | < 190 | < 240 | 685 – 1465 |

* Assumes declining production of landfill gas from sources developed in earlier scenarios.

**Scenario Descriptions**

*Scenario 1:* In this scenario, it is assumed that there is no improvement in current costs and technological status by the year 2000. The potential contribution by the year 2005 is assessed.

*Scenario 2:* In this scenario, an attempt is made to account for cost and technological improvements which may occur by the year 2000. Given these improvements, the potential contribution by the year 2005 is reassessed.

*Scenario 3:* The projections in this highly speculative scenario are based on assumptions that significant improvements in technology and costs could occur by the year 2010. The potential contribution by the year 2014 is assessed.

Note that scenarios are used as guides but cannot be applied uniformly to all six technologies. For example, projections of generation from municipal solid waste depend greatly upon government policy. In the absence of the government's existing policy limiting waste incineration, the favourable costs associated with electricity-from-waste could drive use of the technology to its fuel-limited potential.

*Figure ES-9: Comparison of Potential Contribution Estimates – Alternative Energy Review versus Earlier Estimates*

| Technology | Potential Contribution (MW) | | | |
|---|---|---|---|---|
| | Alternative Energy Review | | Demand/Supply Options Study (1985) (By Year 2004) | 1990 Non-Utility Generation Plan (By Year 2000) |
| | Scenario 1 (By Year 2005) | Scenario 2 (By Year 2005) | | |
| Photovoltaics | < 1 | < 1 | Insignificant | Insignificant |
| Wind | < 1 | < 1 | Insignificant | Insignificant |
| Fuel Cells | < 1 | < 10 | Insignificant | Insignificant |
| Biomass | | | | |
| (1) Waste | 100 | 100 | 50 | 300* |
| (2) Plantation/Forest | Nil | 20 | Nil | Nil |
| Peat | Insignificant | 20 | Insignificant | Insignificant |
| Municipal Solid Waste | | | | |
| (1) Landfill gas | 60 – 70 | 60 – 70 | N/A | |
| (2) Mass Burn | < 15 | < 15 | 50 | 116(1) |
| **Totals** (Approximate) | < 190 | < 240 | 100 | 416 |

* Includes currently installed non-utility generation capacity.

(1) Includes some landfill gas electricity generation.

## 7. Summary and Conclusions

This assessment of the potential for the use of alternative technologies in Ontario in the foreseeable future indicates an increase over the assessment contained in the Demand/Supply Plan. These new estimates are being adopted for planning purposes. Potential energy contributions from alternative energy technologies, even if they prove to be greater than estimated in this review, would still be relatively small compared to the amount of new demand/supply options which would be needed as identified in the Demand/Supply Plan.

This review found that the technologies that show the most future promise are fuel cells, photovoltaics and biomass. The use of municipal solid waste as a fuel is economically viable. However, government policies prohibit the implementation of new facilities. Peat, while an indigenous fuel, is expensive.

Interest in alternative energy technologies results in part from environmental advantages over conventional generating technologies. Examination of the alternative technologies confirms that several are environmentally promising. Environmental effects are influenced by choices of technology, material and fuel.

Photovoltaics, wind power and fuel cells are modular technologies. Modularity has advantages in that small increments in capacity can be added when and where needed and economies associated with high volume production are possible.

With the exception of the burning of municipal solid waste, cost continues to be a significant barrier to utility-scale application of alternative generation technologies in Ontario. However, private individuals and corporations (non-utility generators) may adopt some of these technologies in the absence of access to the electricity grid, for cogeneration applications, or for demonstration purposes. It is expected that non-utility generators will continue to assess these and other technologies and will come forward with proposals to implement capacity when and if these options become economical.

Beyond the year 2000 some alternative energy technologies may find increased use if technological breakthroughs or economies of scale lead to significant cost reductions. Increased use of these technologies may also result from positive assessments of their environmental impact and/or fuel efficiency. Technologies which maximize efficient use of conventional fuels could become increasingly attractive should fuel prices rise and environmental concerns increase.

As stated in the Demand/Supply Plan, Ontario Hydro continues to be involved in research and development concerning many generation concepts which have promising applications.

# Part 1: Background

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## 1-1 Purpose of Alternative Energy Review

.1 The purpose of the Alternative Energy Review is to review and assess energy options which are alternatives to conventional sources for electricity generation in Ontario and to consolidate information available within Ontario Hydro.

.2 Alternative energy technologies examined in this report include electricity generation using solar and wind power, fuel cells, biomass, peat and municipal solid waste.

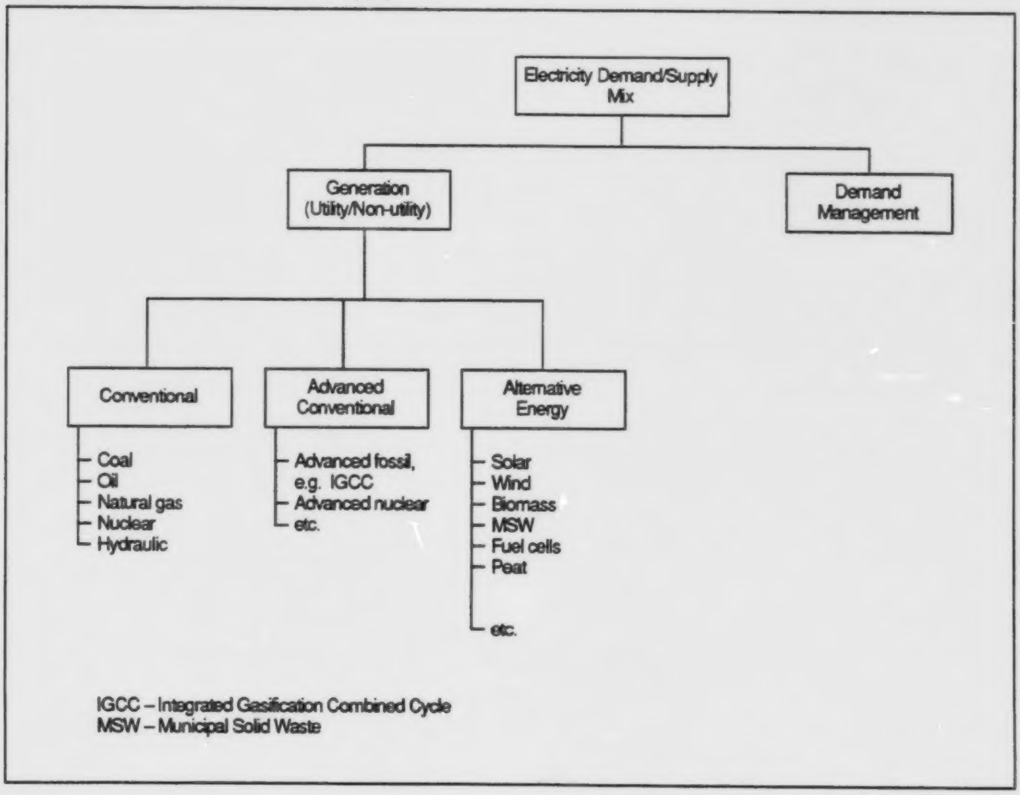
.3 Figure 1-1-1 shows alternative energy technologies in the context of the broader electricity demand/supply mix.

## 1-2 Scope of the Review

.1 The Alternative Energy Review considers a range of alternative technology concepts which include: (1) concepts that use renewable energy resources, such as solar and wind energy, (2) concepts that use fuels indigenous to Ontario, such as peat, biomass and municipal solid waste, and (3) concepts, such as fuel cells, that directly convert the chemical energy of conventional fuels to electricity.

.2 The concepts surveyed in the Alternative Energy Review vary in the extent to which they are developed and practised at the demonstration and commercial levels.

*Figure 1-1-1: Electricity Demand/Supply Mix*


Electricity Demand/Supply Mix
Generation (Utility/Non-utility)
Demand Management
Conventional
Advanced Conventional
Alternative Energy
Coal
Oil
Natural gas
Nuclear
Hydraulic
Advanced fossil, e.g. IGCC
Advanced nuclear
etc.
Solar
Wind
Biomass
MSW
Fuel cells
Peat
etc.
IGCC – Integrated Gasification Combined Cycle
MSW – Municipal Solid Waste

.3 Some concepts are rapidly evolving. This review represents an assessment, at a moment in time, of these technologies. Specific options for each of the concepts are selected for economic assessment on the basis of potential use in Ontario, technological maturity and available costing information.

.4 Recognizing that many alternative generation concepts are not cost effective at present but that technical developments are leading to steady improvements, the review discusses the potential future technical status and use of these technologies.

.5 To limit the size and complexity of this report alternative energy concepts are dealt with as discrete technologies although in some instances hybrid systems have been and will continue to be developed and utilized.

.6 The Alternative Energy Review does not deal with advanced nuclear technologies, advanced fossil technologies and demand management options.

## 1-3 Report Structure

.1 The Alternative Energy Review is structured in three parts.

.2 Part 1, *Background*, describes the purpose and context of the report and provides general background on costing methods, environmental considerations, and assessment criteria. Part 1 identifies those technologies which are considered sufficiently feasible to be described and evaluated in detail in Part 2.

.3 Part 2, *Technology Assessments*, describes and evaluates selected concepts. Each chapter includes a discussion of environmental considerations. Specific electricity generation options are selected for costing on the basis of a judgement of their technological and commercial maturity and potential for application in Ontario. Part 2 includes cost estimates for each of the selected options. Each chapter concludes with an assessment of the potential of each technology.

.4 Part 3, *Summary and Conclusions*, recaps the assessments of the six alternative technologies described in Part 2, and includes a concluding assessment of their possible contribution to Ontario's energy supply mix in the near future.

.5 The *Appendices* provide general background information on overall environmental policies and regulations, and descriptions of conventional thermal generation concepts and applicable emission control concepts.

## 1-4 Concepts: Keeping Up To Date

.1 Ontario Hydro follows developments in alternative energy concepts on a continuing basis through:

- literature searches,
- contacts with other utilities, consultants, non-utility generators, equipment suppliers, industry and research organizations such as the Electric Power Research Institute (EPRI) and the Solar Energy Research Institute (SERI), and
- membership in associations such as the Canadian Electrical Association, the Solar Energy Society of Canada Inc., the Canadian Wind Energy Associations, the Canadian Institute of Energy and the Utility Renewable Resources Association.

.2 Hydro undertakes studies of alternative energy concepts, both internally and through external consultants.

.3 Hydro participates in demonstration projects on its own and with others to develop technical and cost information on new energy concepts.

.4 Examples of these demonstration projects are the Fort Severn wind turbine/diesel hybrid installation, the grid interactive photovoltaic system at the Kortright Centre for Conservation, the remote community photovoltaic system at Big Trout Lake, and the Thunder Bay grain waste/coal cofiring combustion test.

## 1-5 Ontario Hydro Demand/Supply Plan

.1 Ontario Hydro's Demand/Supply Plan (DSP) was issued in December, 1989. (Ontario Hydro, 1989a)

.2 The DSP recommends a diverse mix of demand and supply options to meet Ontario's electricity needs up to the year 2014.

.3 The following perspective on alternative energy generation technologies was adopted within the DSP.

"Three possible roles are foreseen for alternate technologies to make a contribution to Ontario's future electricity supply. These are:

(a) Small increments of capacity which can be implemented by Ontario Hydro without the large financial commitments and long lead times associated with large generating plants.

(b) Parallel generation schemes, such as industrial cogeneration, which can be economically integrated into customer loads and used to provide firm power or to defer the requirements of new capacity.

(c) Supply to loads remote from the electrical grid."

The DSP also stated that:

"Hydro will continue to do research and development on many generation concepts which have promising applications. Hydro is also keeping abreast of research and development by others and is ready to respond if a major technological breakthrough occurs." (Ontario Hydro, 1986; Ontario Hydro, 1989a)

## 1-6 Environmental Requirements

.1 The planning and regulatory environments exist in a state of continual change. For the purposes of this report control technolcgies required to meet any regulations or guidelines in effect as of January, 1991 have been included in the analyses. Figure 1-6-1 lists several existing and proposed air emissions standards used to assess necessary emission controls.

.2 In situations where provincial, federal, and Ontario Hydro standards apply or overlap, the most stringent standard would be used.

.3 Pending legislation, such as the federal $NO_x$/VOC (oxides of nitrogen/volatile organic compounds) management plan and the Ontario Clean Air Program, if passed, would in many instances result in more stringent standards than are presently in place. (CCME, 1990)

.4 Information regarding other policies and regulations that apply to Ontario Hydro is outlined in Appendix A of this review.

### 1-6-1 Approaches to Environmental Analysis

.1 Each of the alternative technology concepts addressed in this report includes a discussion of environmental considerations. The natural environment is considered under the headings of air, land, water, and other. The social environment is considered under the headings of socio-economic effects (e.g., employment, economic development, community impacts) and societal considerations (e.g., social acceptance, lifestyle impacts, sensitive groups, distribution of risks and benefits).

.2 This review considers environmental effects associated with fuel extraction and processing, construction, operations and maintenance, and decommissioning.

.3 In the case of technologies which would require the purchase of pre-fabricated items, such as photovoltaic arrays, the management of environmental effects associated with fabrication are assumed to be included in the price of the items, and are not addressed in detail.

.4 Regulation 308 under the provincial Environmental Protection Act provides maximum allowable ground level concentrations for various emissions. However, since site specific information is required to assess the ability to meet this regulation, such assessments are beyond the scope of this report.

## 1-7 Economic Assessment Methodology

### 1-7-1 Purpose of Providing Costs

.1 The purpose of providing costs in this review is to give an indication of the likely range of costs of the various technologies assessed, not to provide precise cost estimates. Two types of costs are considered – current (1991) costs and projected (year 2000) costs.

### 1-7-2 Current Costs and Projected Year 2000 Costs

.1 Current costs are those costs which would be incurred if the equipment were ordered today. The usual method of preparing cost estimates is to estimate current costs then to escalate those costs to the year when the cash flows are expected to occur.

*Figure 1-6-1: Air Emissions Standards/Guidelines (January 1991)*

| Parameter | Existing | | Proposed/Interim | |
|---|---|---|---|---|
| | Maximum Concentration | Standard/Guideline | Maximum Concentration | Standard/Guideline |
| $NO_x$ | 258 nanograms/ joule (ng/J) of heat input | Federal Clean Air Act (1981) (guideline for fossil fuels but assumed applicable to alternative technologies) | 100 ng/J of heat input (outside Windsor/Quebec City corridor, after year 2000)<br>200 ng/J of heat output (in Windsor/Quebec City corridor, after 1995) | Proposed Federal $NO_x$/VOC Plan (Initiative N305, applicable to new coal stations but assumed applicable to alternative technologies)<br>Proposed Federal $NO_x$/VOC Plan (Initiative N602, applicable to new fossil stations but assumed applicable to alternative technologies) |
| $SO_x$ | 258 ng/J of heat input | Federal Clean Air Act (1981) (guideline for fossil fuels but assumed applicable to alternative technologies) | | |
| Particulates | 43 ng/J of heat input | Federal Clean Air Act (1981) (guideline for fossil fuels but assumed applicable to alternative technologies) | 90mg/$Rm^3$ for untreated wood waste<br>20 mg/$Rm^3$ for treated wood waste | Interim limits for particulates in Ontario being imposed by MOE pending Clean Air Program legislation. |

R = Reference Flue Gas Conditions (25°C, dry, 1 atm, 11% $O_2$)
VOC = Volatile Organic Compounds

.2 Projected (year 2000) costs are predicted costs in the year 2000.

.3 Several of the technologies assessed in this report, namely, the burning of solid biomass (wood), peat and municipal solid waste, utilize conventional and mature combustion technologies. Only current cost estimates are provided for these concepts since it is considered that there is little potential for significant capital cost reductions.

.4 For the other three technologies (photovoltaics, wind and fuel cells), there is the possibility that technological advances, or economies associated with high volume production, could result in significant cost reductions in the future. The approach adopted for these technologies is to provide two sets of costs – current costs and projected (year 2000) costs. The year 2000 was selected on the premise that, should a particular technology become commercially viable by the year 2000, there would be a good likelihood of that technology achieving some market penetration before the year 2014, the end of the planning period.

.5 Particular subsets of some of the technologies, most notably fuel cells, have yet to be demonstrated on a commercial scale. In these instances it is inappropriate to present current costs since the technologies are not commercially viable today. The costs available are for demonstration projects only.

.6 An in-service date of 2002 is used in all of the evaluations in order to be consistent with previous Ontario Hydro evaluations. (Ontario Hydro, 1988, 1989a, 1989b)

### 1-7-3 Cost Estimating Methodology

.1 The current and projected costs of the solar, wind and fuel cell options assessed in this report are derived mainly from estimates made by manufacturers and other estimates obtained through literature reviews. Ontario Hydro judgement is then applied to these estimates to derive cost estimates relevant to Ontario.

.2 The costs presented for the biomass, peat and municipal solid waste (MSW) options are derived from studies prepared by or for Ontario Hydro.

.3 The costs which are presented are Ontario Hydro estimates. Private individuals and non-utility generators may, for various reasons, derive different cost estimates. No attempt is made in this report to estimate costs from a non-utility generator's perspective.

#### *"Point" and "Range" Estimates*

.4 None of the technologies discussed in this report is currently widely used by Canadian utilities for the production of electricity. Accordingly, the range of costs for these technologies tends to be larger than the range of costs for conventional generation technologies.

.5 Although point estimates are derived from the available data, the intent is to indicate the approximate level of the costs, not precise estimates. Sensitivity analyses of cost components and performance factors are used to derive approximate cost ranges.

#### *Cost Models*

.6 The costs of an option can be broken down into three main categories: capital costs; operating, maintenance and administration costs; and fuelling costs. Cost models are used as a guide to ensure that all relevant cost components are considered when evaluating an option. A general cost model is shown in Figure 1-7-1.

.7 As shown in Figure 1-7-1, capital costs are further broken down into initial capital costs and later capital costs.

.8 Initial capital costs include design engineering, construction and installation costs. Any equipment required to meet environmental regulations for emissions from the station would also be included in initial capital costs. Capital costs are normally expressed in dollars or dollars per kilowatt ($/kW).

.9 Later capital costs include major capital modifications during the life of a station, and decommissioning costs. Later capital costs are usually expressed in dollars per year or dollars per kilowatt per year ($/kW/yr).

.10 Operating, maintenance and administration (OM&A) costs include such costs as the salaries of station operating and maintenance staff and costs of materials and supplies, other than fuel (for example, lubricating oils), used in a station. OM&A costs are usually expressed in dollars per year or dollars per kilowatt per year ($/kW/yr).

.11 Fuelling costs cover the costs of fuel for the station and also include the cost of disposal of the waste generated (if any) as the fuel is used. Fuelling costs are usually expressed in cents per kilowatt-hour (¢/kWh).

.12 A more detailed discussion of cost models is provided in other Ontario Hydro documents. (Ontario Hydro 1988, 1989a, 1989b)

#### *Cost Measures and Cost Terms*

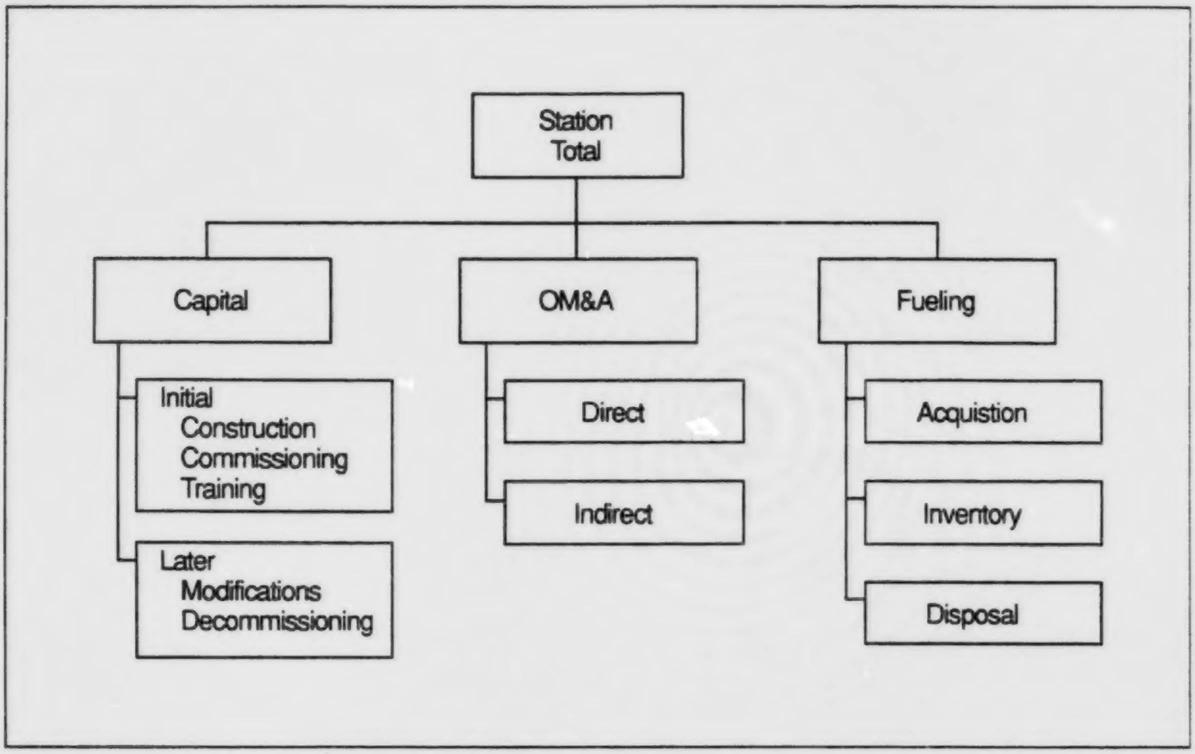
.13 There are several measures which can be used to assess the costs of a particular electricity generation option. The two measures used in this report are the levelized unit energy cost (LUEC) and the cost/benefit ratio (C/B ratio).

.14 The LUEC is a single value in constant dollars representative of the unit cost of energy delivered by an option over its service life. The LUEC measure is explained in detail in other Ontario Hydro reports. (Ontario Hydro 1988, 1989a, 1989b) The LUEC of an option is normally quoted at a specific annual capacity factor.

.15 Annual capacity factor is a measure of the actual energy produced by a plant in a year compared to the maximum amount of energy which could have been produced had that plant operated at full output for the entire year.

.16 The lifetime capacity factors used in assessing the alternative energy options in this review assume high availability and utilization of the option. In practice, these options may be utilized at lower or higher capacity factors depending on a number of factors including the needs of the electricity system and fuel availability. Changes in annual capacity factor significantly influence LUEC estimates. Thus, LUEC estimates calculated at different capacity factors are not comparable.

*Figure 1-7-1: General Cost Model*



.17 In some instances LUEC is not the best measure for evaluating an option's worth to an electricity system. The LUEC measure considers only the costs of an option, with the implicit assumption that the benefits provided by all options are the same. However, this is not always the case. For example, options which are not "dispatchable", (i.e., cannot be depended on to be available when needed), such as solar and wind options, are of less value to the electricity system than options which are dispatchable.

.18 Where LUEC is not the best measure, the cost/benefit ratio can be used. The cost/benefit ratio (C/B) is calculated by dividing the present value of the costs (capital, operating maintenance and administration, and fuelling) of an option over its service life by the present value of the benefits (electrical energy and capacity – see below) which that option would provide to the electricity system over its service life.

.19 In this report, the cost/benefit ratio is used to assess the solar and wind options. The cost/benefit ratio is also used to assess the municipal solid waste (MSW) option, for reasons explained below.

### *Evaluation of Benefits*

.20 The benefits provided by an option to an electricity system fall into two categories: (1) the energy (in kilowatt hours) provided by that option over its service life; and (2) the capacity (in megawatts) which that option provides to the electricity system. In this review, Ontario Hydro's forecast incremental system values of power and energy are used to calculate the value of the energy and capacity of an option.

.21 The capacity provided by a dispatchable option is normally its full nominal rating. These options are said to be eligible for a full "capacity credit". Options which are not dispatchable, such as solar and wind options are, however, not eligible for a full "capacity credit".

.22 The value of the energy produced by an option varies depending on the point on the system at which the option is connected. Options which are particularly suitable for application as dispersed sources of generation receive credits for avoiding transmission and distribution costs and losses. The specific transmission and distribution credits which are applied in evaluating the economics of each technology option are discussed in Part 2 of this review.

.23 In this review options which are deemed to be renewable sources of energy (solar and wind energy fall into this category), receive a 10 percent "renewables" credit to reflect societal preference for these options.

### *Assessment of Municipal Solid Waste Options*

.24 The cost of plants which burn municipal solid waste should be viewed in light of their contribution towards the avoidance of waste disposal costs. The "tipping fees" paid to an operator of an MSW incineration plant to receive the waste provide substantial revenue. Electricity, if produced, is a byproduct of MSW incineration. The benefits associated with the operation of the plant are a combination of the revenues provided by the tipping fees and the revenues from the sale of electricity.

.25 Thus, in evaluating the economics of MSW incineration plants it is more appropriate to calculate cost/benefit ratios (using the combined benefits discussed above) rather than LUEC.

### *Value of Useable Heat*

.26 The fuel cell, biomass, peat and municipal solid waste options may be well suited to cogeneration applications, producing both electricity and useable heat. The heat can be used on-site in an industrial or commercial application which would make these options more attractive to non-utility generators. The heat may also be sold, for example for district heating.

.27 The potential economic benefit derived from the use or sale of the heat has not been included in the above economic assessments. The magnitude of the potential benefit depends on the amount of useable heat produced and on assumptions made about the value of the heat. Note that options with high fuel-to-electricity conversion efficiencies will have correspondingly lower amounts of useable heat available for cogeneration applications. If it is assumed that the cogeneration application is optimal such that about 80 percent of the energy content of the fuel is recovered as useable heat or electricity and that the heat is valued at a particular price, (for example, the commercial/industrial price of natural gas) then the value of the heat could result in a lifetime levelized unit energy benefit. That benefit would depend on the additional costs which would be incurred for the installation and operation of heat recovery and distribution equipment.

.28 The value of the potential heat credit for each of the technology options assessed in this review is given in Part 2, Sections 1-10, 2-10, 3-10, 4-10, 5-10 and 6-10.

### *Factors Influencing Costs*

.29 The factors which influence the costs of particular options are discussed in detail in other Ontario Hydro documents. (Ontario Hydro 1988, 1989a, 1989b)

.30 For the purposes of this report only a brief overview of these factors is given, with emphasis on the factors which are particularly important to a review of the costs of alternative energy options.

.31 Many factors influence the costs of an option. Some factors influence primarily capital costs, others influence primarily operating and maintenance costs while still others influence primarily fuel costs.

.32 Factors which influence primarily capital costs include:

- maturity of the technology,
- unit size,
- need for environmental control equipment,
- frequency and cost of capital modifications, and
- decommissioning costs.

.33 Factors which influence primarily operating and maintenance costs include:

- ease of operation and maintenance,
- degree of maintenance required,
- annual capacity factor/system utilization, and
- unit size/number of units at one site.

.34 Factors which influence primarily fuel costs include:

- fuel availability,
- ease of handling and preparation,
- amount of waste (e.g., ash) generated/cost of disposal, and
- efficiency of the option.

.35 The useful life of an option is also a major influence on costs. Given two options with the same initial capital cost, the one with a longer useful life provides a longer period over which the initial cost of the option can be recovered through the sale of electricity. Thus this option may have a lower lifetime unit cost of electricity.

### 1-7-4 Economic Evaluations

.1 Economic evaluations of the six technologies assessed in this report are provided in Part 2, Sections 1-10, 2-10, 3-10, 4-10, 5-10 and 6-10.

.2 Unless otherwise stated, all costs and benefits are stated in 1991 dollars.

## 1-8 Assessment Methodology

*Assessment Criteria*

.1 To assess the potential contribution of the alternative energy technologies reviewed in this report to the electricity supply mix in Ontario during the planning period, a number of criteria are considered including the following:

- status of technological development (e.g., concept phase, pilot plants, demonstration or commercial projects),
- costs (including current and projected costs for some technologies),
- environmental considerations,
- plant availability/reliability,
- fuel availability and cost,
- operational considerations,
- maintenance requirements,
- siting requirements/restrictions,
- modularity,
- suitability for centralized or dispersed generation, and
- suitability for on-grid or off-grid use.

.2 Several of these assessment criteria influence the potential system applications of the technologies as well as the potential contribution of the technologies (in megawatts) to the electricity supply mix in Ontario. The potential system applications and the method of assessing the potential contribution of the technologies are discussed in more detail below.

*Potential System Application*

.3 The potential system application of an alternative technology option is influenced by many factors including plant availability and reliability, electricity production costs, siting requirements and/or restrictions, operational considerations, suitability for on-grid or off-grid use, suitability for centralized and/or dispersed generation, and dispatchability.

.4 These factors influence not only whether the technology option would be a suitable and effective addition to the electricity supply mix, but also where the option would be best sited and the type of loads which the option would best serve.

.5 The distinction between base, intermediate and peak loads is explained in other Ontario Hydro documents. (Ontario Hydro 1988, 1989a, 1989b)

.6 To explain briefly, base loads are those loads which must be met on an almost continuous basis, throughout a day, week, month or year. These loads typically persist for 70 to 100 percent of the time. Options which are used to meet base loads must be dispatchable and should be capable of attaining lifetime capacity factors in the range of 60 to 80 percent. Electricity production costs should also be amongst the lowest of all available options.

.7 Intermediate loads are those which must be met about 20 to 70 percent of the time, mainly during daytime periods. Options which are used to meet intermediate loads must be dispatchable and should be capable of attaining lifetime capacity factors in the range of 40 to 60 percent.

.8 Peak loads are those loads which persist up to 20 percent of the time, mainly during the daily peak periods, and usually during winter weekdays. Options which are used to meet peak loads should also be dispatchable (although, if the option's availability coincides with the time of the peak load, this could also be acceptable) and usually attain lifetime capacity factors of up to 20 percent.

.9 For example, energy from solar technology options, because it is not available around the clock, is not suited for meeting base loads. Similarly, wind energy, because it is not continuously available and its availability may be difficult to predict, cannot be depended on to meet base loads. These options are said to be non-dispatchable. As discussed in Section 1-7, the value of these options to an electricity system is lower than the value of conventional, dispatchable options.

.10 Solar and wind energy options, because they are not dispatchable, could potentially result in changes to the operation of electricity systems. When these options provide only a small portion (say, less than 5 percent) of the total electricity demand, their impact on the operation of an electricity system should not be a concern. However, at higher penetration levels solar and wind energy options become less valuable to an electricity system. For example, the increased cost associated with maintaining additional generation reserve to compensate for the non-dispatchability of solar and wind options may outweigh or offset some of the benefits of having these options on the system. This issue would need to be studied and resolved before solar and wind options could achieve high penetration levels.

.11 Several of the options assessed in the review would be best utilized as small, dispersed sources of generation. As discussed in Section 1-7, dispersed sources of generation can be advantageous because transmission and distribution costs and losses can be reduced. However, the widespread implementation of small, dispersed sources of generation on an electricity system could require changes to the manner in which that electricity system is operated. These matters would need to be studied and resolved before there could be a substantial shift towards small, dispersed sources of generation.

***Assessment of Potential Contribution***

.12 The above factors are considered in assessing the potential contribution to the electricity supply mix in Ontario of the alternative energy technologies considered in the review.

.13 The potential contribution is assessed under three different scenarios as follows:

*Scenario 1*: In this scenario, it is assumed that there is no improvement in current costs and technological status by the year 2000. The potential contribution by the year 2005 is assessed.

*Scenario 2*: In this scenario, an attempt is made to account for cost and technological improvements which may occur by the year 2000. Given these improvements, the potential contribution by the year 2005 is reassessed.

*Scenario 3*: The projections in this highly speculative scenario are based on assumptions that significant improvements in technology and costs could occur by the year 2010. The potential contribution by the year 2014 is assessed.

.14 Note that scenarios are used as guides but cannot be applied uniformly to all six technologies. For example, projections of generation from municipal solid waste depend greatly upon government policy. In the absence of the government's existing policy limiting waste incineration, the favourable costs associated with electricity-from-waste could drive use of the technology to its fuel-limited potential.

## 1-9 References

CCME, 1990, Management Plan for Nitrogen Oxide ($NO_x$) and Volatile Organic Compounds (VOCs) – Phase 1, November 1990. Canadian Council of Ministers of the Environment.

Ontario Hydro, 1986, Demand/Supply Options Study.

Ontario Hydro, 1988, Ontario Hydro Presentations to the Ontario Nuclear Cost Inquiry.

Ontario Hydro, 1989, Demand/Supply Plan.

Ontario Hydro, 1989a, Thermal Cost Review.

## 2-1 Purpose

.1 This chapter lists alternative energy concepts and identifies those which are considered in detail in this review.

## 2-2 Alternative Energy Generation Concepts

.1 There are many alternative energy concepts including the following:

- Solar
- Wind
- Fuel Cells
- Biomass
- Peat
- Municipal Solid Waste (MSW)
- Nuclear Fusion
- Geothermal
- Ocean Thermal
- Tidal / Wave
- Novel Cogeneration

.2 *Solar* energy concepts refer to the generation of electricity from sunlight, either directly using photovoltaics, indirectly by the concentration of sunlight to generate sufficient heat to drive a thermal generation cycle, or by the use of sunlight to produce a fuel such as hydrogen which can be used at a later stage to generate electricity.

.3 *Wind* energy concepts refer to the use of wind energy to drive an electricity generator.

.4 *Fuel cell* concepts refer to the use of a device which directly converts the chemical energy of a fuel to electricity without combustion.

.5 *Biomass, peat* and *municipal solid waste* concepts involve the use of these materials as fuels to generate electricity.

.6 *Nuclear fusion* concepts refer to the fusion (combining) of two lighter nuclei to form a heavier nucleus with the release of energy. The energy can be used to drive a heat engine to generate electricity.

.7 *Geothermal* concepts refer to the use of the earth's heat to drive heat engines to generate electricity.

.8 *Ocean thermal* concepts refer to the use of the temperature gradient between the sun-warmed ocean surface and cooler deep waters to drive a low temperature heat engine to generate electricity.

.9 *Tidal* and *wave* power concepts capture the energy in ocean tides and waves to generate electricity.

.10 *Novel cogeneration* involves the recovery and use of low quality (i.e., low temperature) heat energy for use in electricity generators. Low quality heat is a byproduct of industrial processes such as steelmaking, pulp and paper production, and refining. Ontario Hydro is assessing the potential of novel approaches such as Thermal Energy Conversion technology. Originally developed for Ocean Thermal Energy Conversion applications, such technologies may be applied to the generation of electricity using the low temperature waste heat rejected at fossil-fuelled and nuclear generating stations.

## 2-3 Alternative Energy Concepts Selected for Evaluation

### *Concepts Considered*

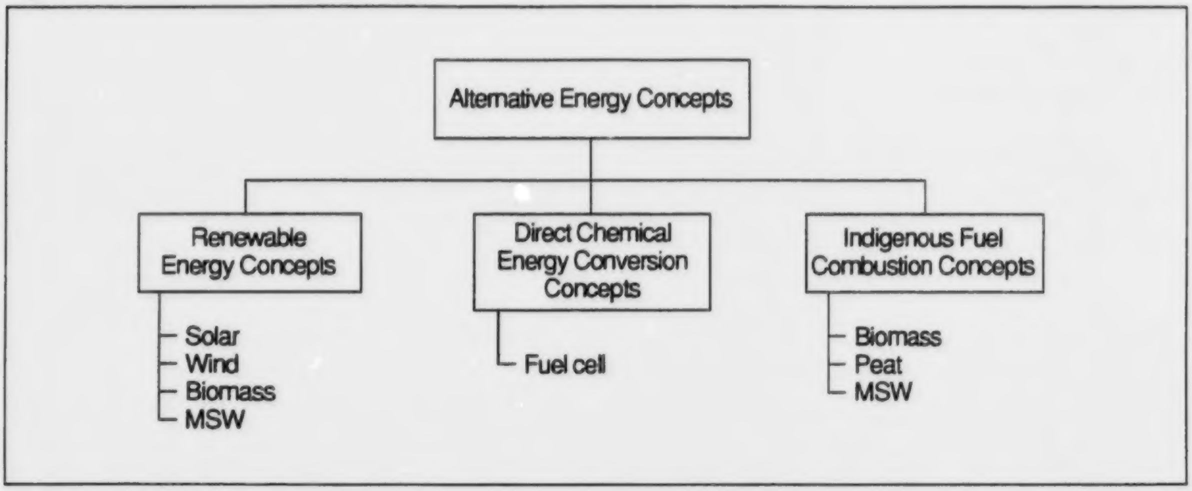
.1 The alternative energy concepts selected for further discussion in Part 2 are summarized in Figure 2-3-1.

.2 As shown in Figure 2-3-1 these concepts may be divided into concepts that:

- use a renewable and cost-free energy source, such as sunlight or wind,
- convert the chemical energy of a fuel directly to electrical energy, as in fuel cells, or
- burn fuels, derived from biomass, peat and municipal solid waste, which are indigenous to Ontario.

.3 Thermal generation technologies are discussed in Appendix B.

*Figure 2-3-1: Alternative Energy Concepts*


Alternative Energy Concepts
Renewable Energy Concepts
Solar
Wind
Biomass
MSW
Direct Chemical Energy Conversion Concepts
Fuel cell
Indigenous Fuel Combustion Concepts
Biomass
Peat
MSW

### *Concepts Not Considered*

.4 Concepts which are not expected to be practicable by 2014 and concepts which are not feasible in Ontario are not considered further.

.5 Nuclear fusion concepts are highly unlikely to reach commercial implementation before 2014.

.6 Ocean thermal, geothermal, and tidal or wave power concepts are not considered practical in Ontario. Novel cogeneration is still at the concept stage.

.7 Solar energy concepts include the use of solar energy to produce hydrogen which can be used as a clean-burning fuel for a variety of applications including electricity generation. While this technology may hold promise for the longer term it is still in the conceptual stage and is unlikely to be implemented on any significant scale before 2014 because of the technological and cost barriers that must be overcome.

.8 Solar satellites located in orbit above the earth to collect sunlight and beam the energy to earth in the form of microwaves are also in the conceptual stage and are unlikely to be implemented before 2014.

## 2-4 Fuels

.1 Figure 2-4-1 identifies several key attributes related to fuels for the selected alternative energy concepts.

.2 *Renewable* fuels are those, such as sunlight and wind, which can be replenished at the rate at which they are used.

.3 *Indigenous* fuels are those found in Ontario.

.4 Processes that use conventional fuels with higher *efficiency* (e.g., fuel cells fuelled by natural gas) than conventional processes result in less rapid depletion of available reserves of conventional fuels and, often, proportionally lower pollutant emissions to the natural environment per unit of energy generated.

.5 Some concepts are more suited than others to cogeneration, the production of electricity and useable heat.

*Figure 2-4-1: Key Fuel Attributes of Selected Alternative Energy Concepts*

| Concept | Renewable Fuel | Indigenous Fuel | Improved Efficiency | Useable Heat | Environmental Emissions | Land Use | Fuel Wastes |
|---|---|---|---|---|---|---|---|
| Solar | Y | Y | – | N | N | Y* | N |
| Wind | Y | Y | – | N | N | Y* | N |
| Fuel Cells | N** | N** | Y | Y | Y** | N | Y** |
| Biomass | Y | Y | – | Y | Y | Y | Y |
| Peat | N | Y | – | Y | Y | Y | Y |
| MSW | Y | Y | – | Y | Y | N | Y |

* Depends on application (e.g., centralized versus dispersed).
** Fuel dependent.

## 2-5 Environmental Emission Control Concepts

.1 Alternative energy generation using biomass, peat and MSW as combustion fuels require emission controls to reduce emissions to the environment. In identifying necessary emission controls the following were considered:

- current environmental regulations and guidelines (see Part 1, Section 1-6 and Appendix A), and
- the available emission control technologies (see Appendix B).

# Part 2: Technology Assessments

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## 1-1 Introduction

.1 Solar energy technologies are shown in Figure 1-1-1.

.2 Solar energy technologies fall into two general categories; passive and active technologies.

.3 Passive solar technologies are those which convert the sun's energy into useable heat without the aid of special equipment to move the heat from a point of collection to a point of utilization. For example, south-facing windows are architectural features which reduce winter heating requirements. Deciduous trees planted in front of the same windows provide summer shade and reduced cooling requirements.

.4 Active solar technologies require the use of equipment and controls to collect and use the sun's energy.

.5 Active solar technologies can be further separated into solar heating and solar electric technologies.

.6 Solar heating uses the sun's energy to heat living space, domestic water, swimming pools, etc. Such systems may employ rooftop heating coils to collect heat which is then transferred to the point of use.

.7 Solar electric technologies may again be subdivided into solar thermal and photovoltaic systems.

.8 Solar thermal systems involve the production of steam to drive turbine-generators much like those in fossil or nuclear-fuelled generating stations. Alternatively, these systems can heat gases to drive Stirling engines or similar devices.

.9 Photovoltaics involve the use of semi-conductors to convert sunlight directly into electrical energy without an intermediate heating stage.

.10 The purpose of this chapter is to describe existing and developing solar electric technologies and to evaluate their potential for application in Ontario. This chapter does not evaluate solar heating options which might displace electricity use, e.g., for domestic water heating.

*Figure 1-1-1: Solar Energy Technologies*

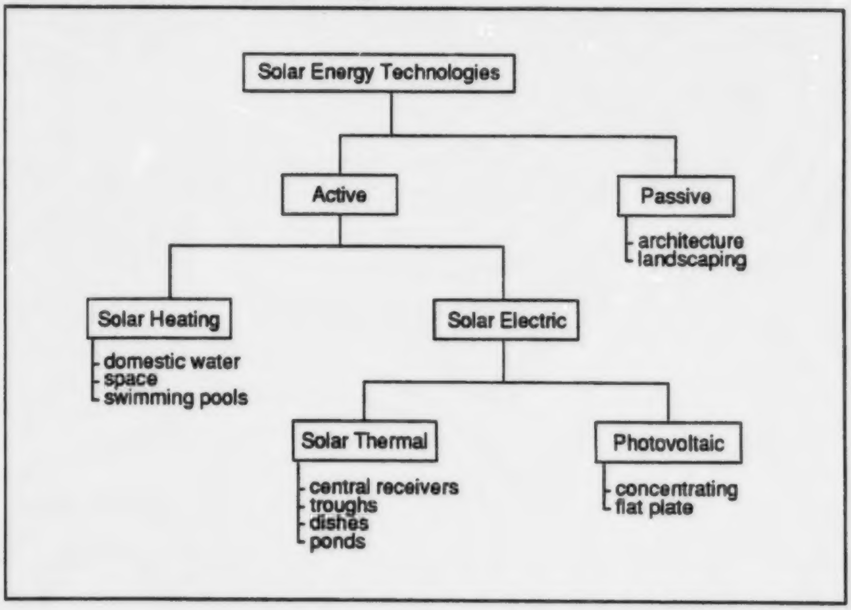
Solar Energy Technologies
Active
Passive
- architecture
- landscaping
Solar Heating
- domestic water
- space
- swimming pools
Solar Electric
Solar Thermal
- central receivers
- troughs
- dishes
- ponds
Photovoltaic
- concentrating
- flat plate

*Figure 1-2-1: Average Daily Total Solar Radiation (MJ/m$^2$) for North America*

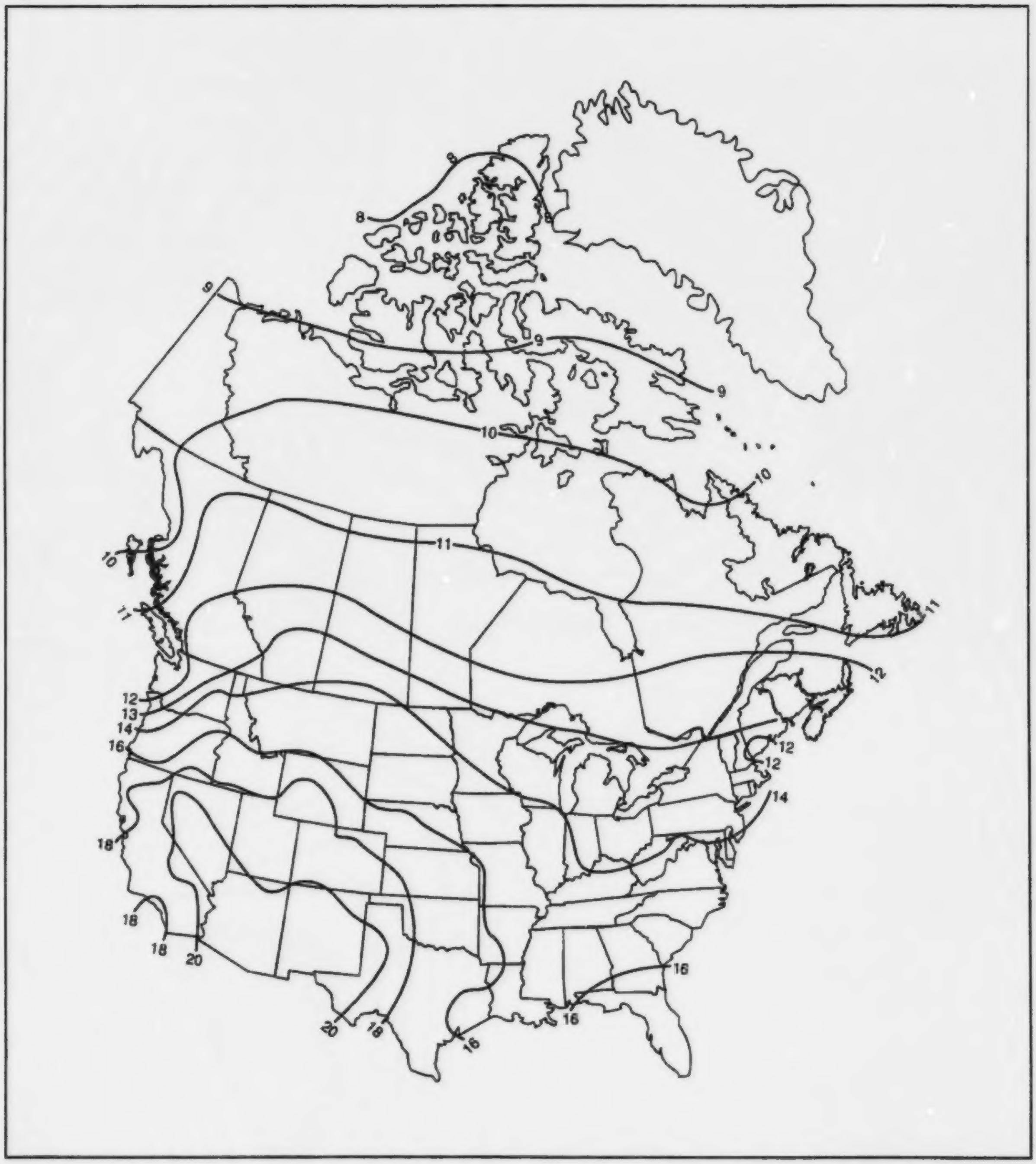
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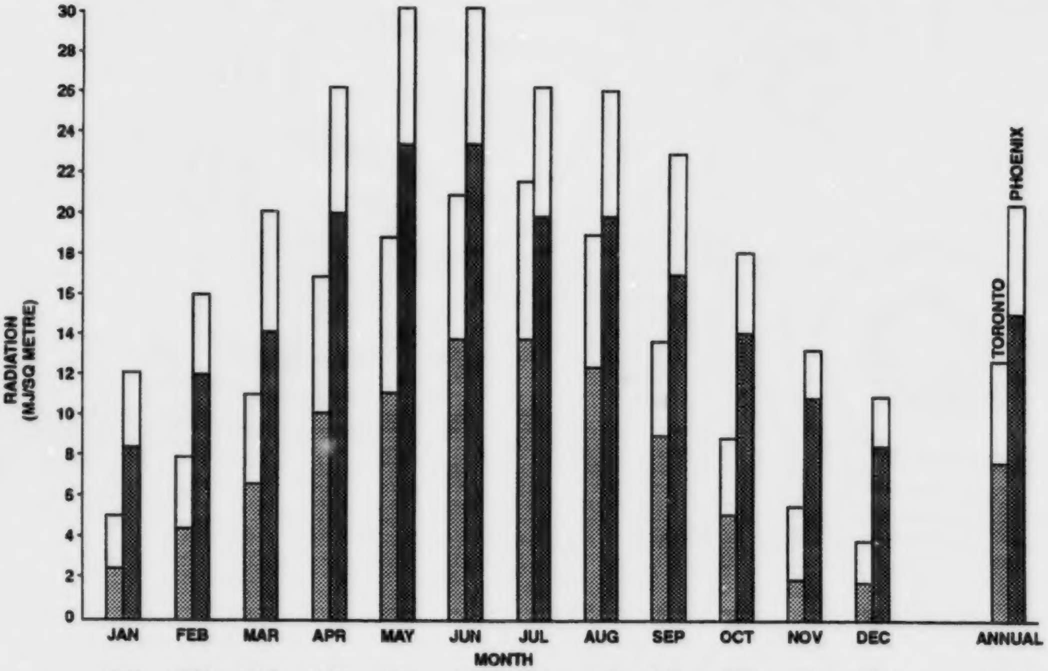
*Figure 1-2-2: Comparison of Solar Radiation in Toronto and Pheonix, Arizona*



| | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | ANNUAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **TORONTO** Total | 5.1 | 7.9 | 11.6 | 17.1 | 18.7 | 20.9 | 21.5 | 18.9 | 13.7 | 8.8 | 4.5 | 3.8 | 12.7 |
| (Direct) | 2.9 | 4.5 | 6.7 | 10.8 | 11.3 | 12.9 | 13.9 | 12.3 | 8.9 | 5.2 | 1.9 | 1.8 | 7.7 |
| **PHOENIX** Total | 12.1 | 16.0 | 20.4 | 26.8 | 30.5 | 30.5 | 26.3 | 26.0 | 22.8 | 18.1 | 13.6 | 11.0 | 20.5 |
| (Direct) | 9.1 | 12.0 | 14.6 | 20.1 | 23.4 | 23.5 | 19.3 | 19.8 | 17.2 | 14.1 | 10.7 | 8.4 | 15.2 |

Toronto ref. Solar Radiation Data Analysis for Canada 1967-1976 • Environment Canada
1985 Publication Cat. No. En 56-64 / 3-1984
Phoenix ref. Solar Radiation Energy Resource Atlas of the United States
SERI Golden, Col. SERI / SP-642-1037 / Oct.1981

■ Direct
☐ Diffuse

## 1-2 Fuel/Energy Source

.1 Solar energy is available only during the day and varies within the day, from day to day, from season to season and from place to place on the earth's surface.

.2 Figure 1-2-1 shows average daily total solar radiation in North America.

.3 Total solar radiation is comprised of two components, direct and diffuse sunlight.

.4 Direct sunlight, light which produces shadows, can be focused.

.5 Diffuse sunlight, such as light which has been scattered by clouds or haze, cannot be focused.

.6 Total solar radiation (on a horizontal surface) is largely determined by latitude.

.7 The ratio of direct to diffuse sunlight is largely determined by climatic factors including amounts of cloud cover and haze.

.8 Figure 1-2-2 illustrates levels of solar radiation in Toronto and Phoenix, Arizona.

.9 Mean daily solar radiation in Toronto is 12.7 megajoules per square metre (MJ/m$^2$) compared with 20.5 MJ/m$^2$ in Phoenix.

.10 Seasonal variation in sunlight is greater at Toronto's higher latitude.

.11 The proportion of direct total radiation is lower in Toronto because of the area's more overcast and hazy climatic conditions.

## 1-3 Technology Description

### 1-3-1 Photovoltaic Electric Technologies

.1 This section describes photovoltaic (PV) electric technologies.

.2 Photovoltaic technologies involve the use of photoelectric cells to convert the sun's light energy to electric energy directly, that is, without an intermediate heating stage.

.3 The cells are made of semi-conducting materials which produce direct current electricity when exposed to sunlight.

.4 Figure 1-3-1 illustrates a simple photovoltaic cell.

.5 Photovoltaic cells are usually packaged into modules which in turn are mounted and wired to form arrays as shown in Figure 1-3-2.

.6 Modules can be assembled into any parallel/series combination to produce arrays with the desired current and voltage characteristics.

.7 Electric current increases with the amount of light which falls upon the cells.

*Figure 1-3-1: Simple Photovoltaic Cell [After Maycock & Stirewolt, 1981]*

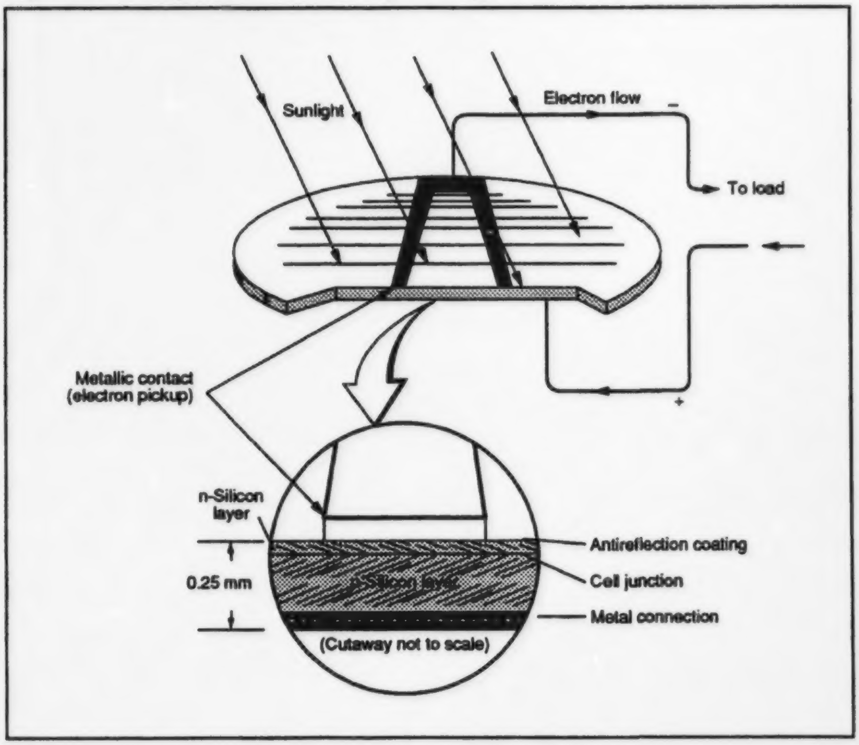
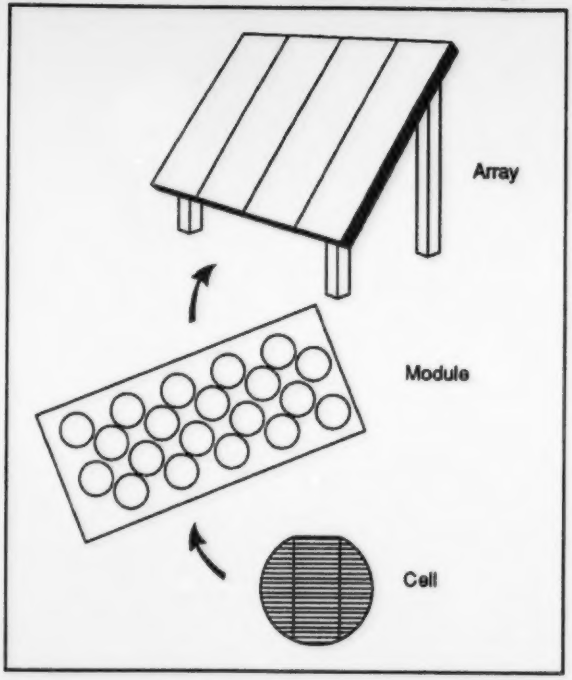

Sunlight
Electron flow
−
To load
+
Metallic contact
(electron pickup)
n-Silicon
layer
0.25 mm
p-Silicon layer
Antireflection coating
Cell junction
Metal connection
(Cutaway not to scale)

*Figure 1-3-2: Photovoltaic Cells, Modules and Arrays*



.8 A typical photovoltaic module measures 1.2 by 0.3 metres and will produce about 50 watts of electric power (at 12 volts d.c.) under standard bright light conditions.

.9 Power conditioning systems are used to convert from direct to alternating current.

.10 As shown in Figure 1-1-1, photovoltaic technologies fall into two main groups; flat plate and concentrating technologies. These groups are illustrated in Figure 1-3-3.

.11 Flat plate technologies convert both direct and diffuse sunlight into electricity – an important consideration in northern climates. Flat plate technology is used by Ontario Hydro at Big Trout Lake.

.12 Concentrating technologies employ lenses or mirrors to focus direct sunlight onto the solar cells. Concentrating arrays were installed at Dallas Airport and utilize that area's higher levels of direct solar radiation.

.13 Photovoltaic technologies can be further subdivided based upon materials used and construction of the cells.

.14 The semiconductors used in the cells can be made of many different materials including those shown in Figure 1-3-4.

.15 The cells themselves can be manufactured in one of several structures as shown in Figure 1-3-4.

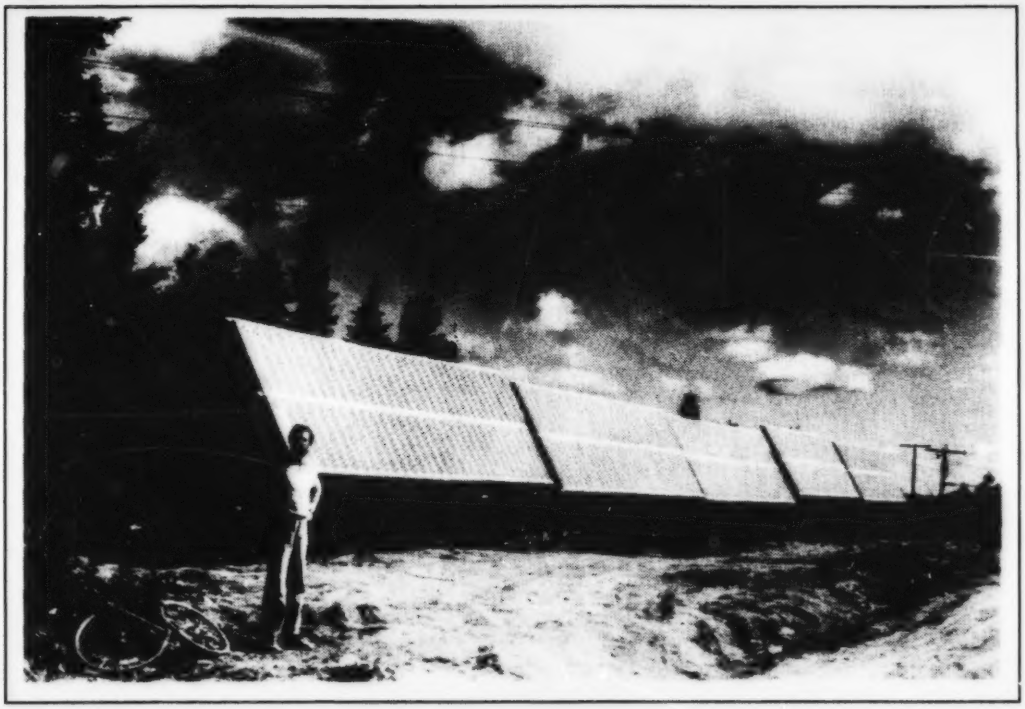
.16 Crystalline flat plate collectors use single or multi-crystal silicon cells, typically about 0.25 mm thick and about 10 cm wide and of square or circular shape.

.17 Thin film cells consist of one or more thin layers (about 1/1000 mm thick) of semiconducting materials such as amorphous (non-crystalline) silicon, copper indium diselenide or cadmium telluride deposited on supporting material such as glass, ceramics, or steel.

.18 Single and multi-crystal silicon technology is well developed and comprises the bulk of the commercial photovoltaic market at this time.

.19 Amorphous silicon cells are used primarily in smaller consumer products such as calculators, cameras and toys.

*Figure 1-3-3: Photovoltaic Technologies – Flat-Plate and Concentrating*



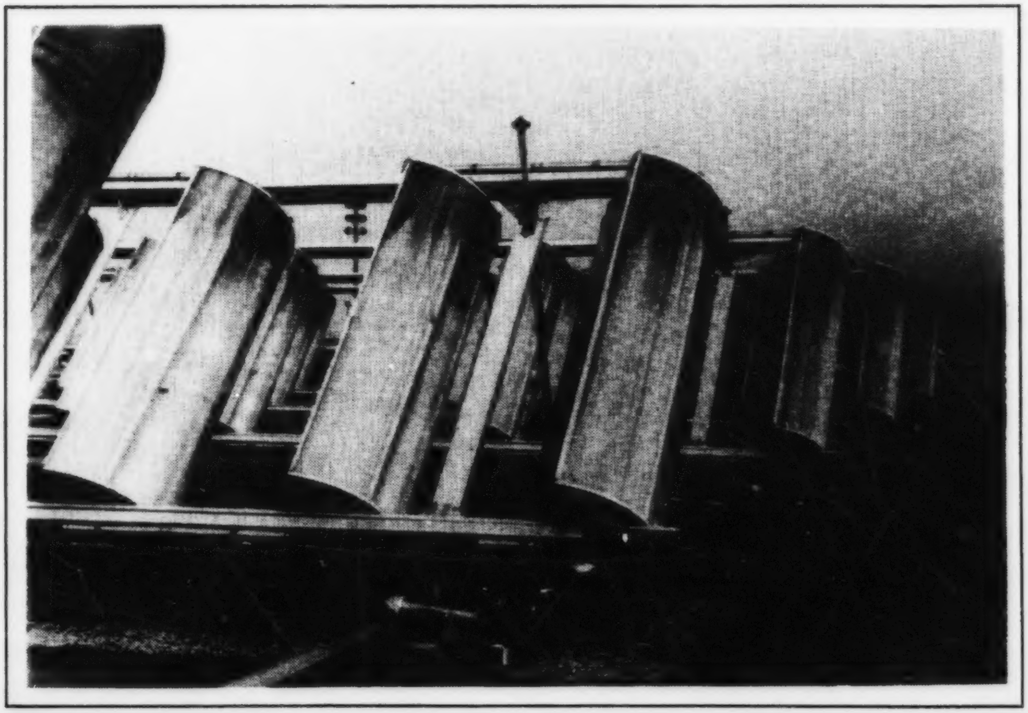


*Figure 1-3-4: Photovoltaic Cell Structures and Materials*

**Photovoltaic cell**

**Structure**
- single crystal
- multi crystal
- amorphous and thin films

**Material**
- silicon
- copper indium diselenide
- cadmium telluride
- gallium arsenide
- etc.

### 1-3-2 Solar Thermal Electric Technologies

.1 This section describes solar thermal electric technologies.

.2 Solar thermal electric technologies utilize primarily the direct component of total solar radiation.

.3 Solar thermal electric technologies fall into four groups; central receivers (power towers), line-focus parabolic troughs, point-focus parabolic dishes, and solar ponds.

.4 Figure 1-3-5 illustrates the four technologies.

.5 These technologies involve solar collectors, receivers, energy storage devices, and conversion equipment to transfer the sun's energy to a working fluid which in turn drives a heat engine to produce electricity. All but solar ponds use mechanisms to track the sun.

.6 Central receiver design involves a large array of flat reflectors (heliostats) each of which tracks the sun to concentrate its rays on a boiler located atop a tower.

.7 Figure 1-3-6 shows the so-called "solar power tower", located in Barstow, California.

.8 Point-focus parabolic dishes resemble satellite dishes and focus light on a central receiver linked to a heat engine. The heat engine can be located at the receiver. Alternatively, heated fluid can be piped through a steam-producing heat exchanger to drive a turbine-generator.

.9 Line-focus parabolic troughs are similar to dishes but use reflective troughs to follow and focus the sun's energy along lines parallel to the troughs. The receivers, specially coated pipes inside glass vacuum tubes, contain synthetic oil or some other medium to transport heat to a generator.

.10 As shown in Figure 1-3-5 solar ponds are shallow ponds with layers of water at different temperatures. The sun's rays pass through the water and heat the bottom of the pond. The higher temperature of the water near the bottom of the pond is maintained by having a higher concentration of salt at the bottom which increases the density of the water thereby suppressing thermal convection.

.11 The hot water (at 80 to 90°C) can be used immediately or stored for later use with a low temperature thermal engine to produce electricity.

.12 Solar ponds require strong direct sunlight and relatively warm ambient air temperatures.

*Figure 1-3-5: Solar Thermal Electric Technologies*

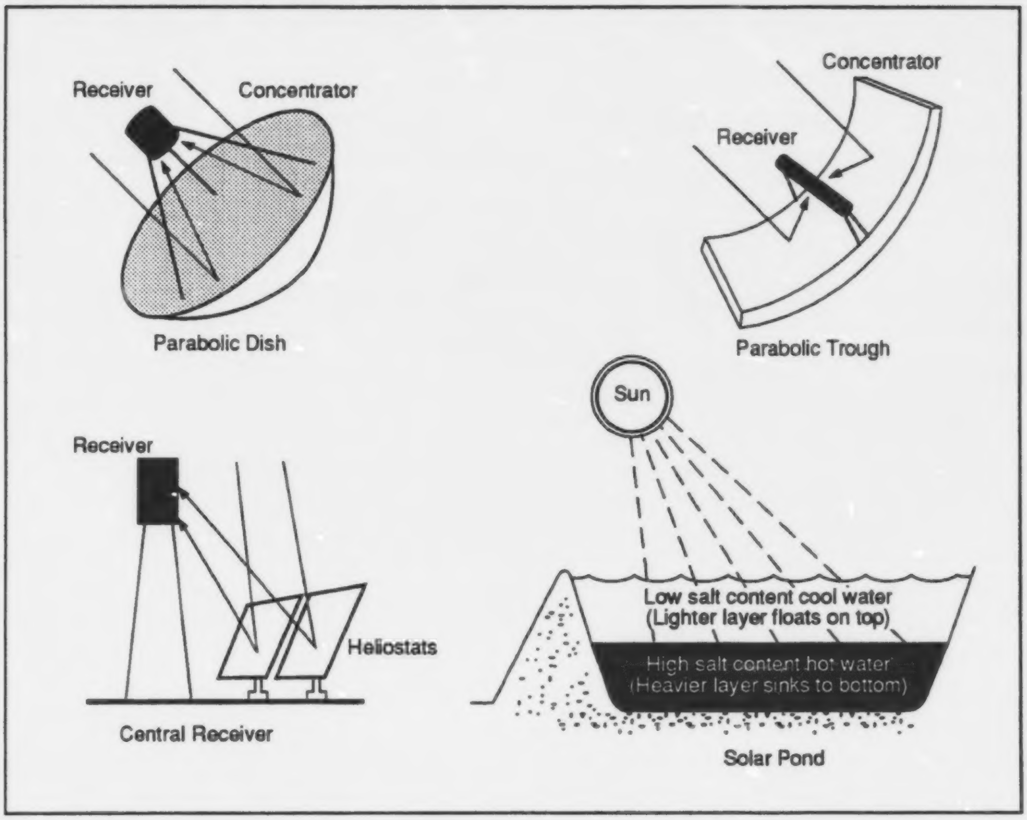
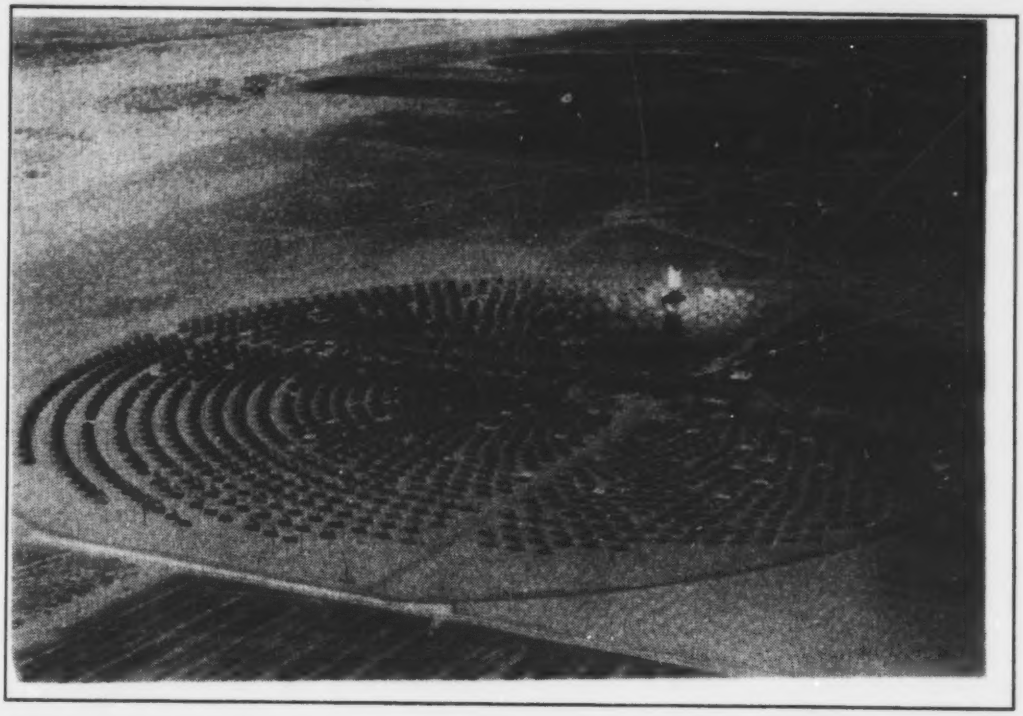

Receiver
Concentrator
Parabolic Dish
Concentrator
Receiver
Parabolic Trough
Receiver
Heliostats
Central Receiver
Sun
Low salt content cool water
(Lighter layer floats on top)
High salt content hot water
(Heavier layer sinks to bottom)
Solar Pond

*Figure 1-3-6: Solar Power Tower Located in Barstow, California [Source: Southern California Edison]*



## 1-4 Experience

### 1-4-1 Photovoltaic Technologies

*World Experience: Photovoltaic*

.1 Photovoltaic technology is well established and widely used throughout the world.

.2 With estimated world photovoltaic capacity nearing 200 MW, the technology can be considered to be well established.

.3 The commercial market is dominated by single and multi-crystal silicon technology, demonstrating efficiencies of 11 to 14 percent in field applications.

.4 The present market for photovoltaics is in niche applications where conventional power is extremely expensive or otherwise not available.

.5 Applications of photovoltaic technology include installations which power homes, telecommunications equipment, lighthouses, remote monitoring stations, irrigation systems, and cottages.

.6 Research to expand and improve photovoltaic technologies continues and is growing globally.

.7 Photovoltaic systems may or may not be connected to an electrical grid system.

.8 Connected systems are referred to as utility interactive; non-connected systems are called "stand alone".

.9 Stand alone systems may or may not be supplied with battery storage and/or backup generators.

.10 Photovoltaic systems suitable for residential use can be purchased from local retailers in many parts of North America, Europe and elsewhere.

.11 Several utilities have installed demonstration rooftop panels in residential communities in the United States, Europe, and Japan.

.12 Most applications are found where there is no cost-effective access to an electrical grid or other sources of electricity. Remote cottage applications account for a rapidly growing market.

.13 In 1990 worldwide sales of photovoltaic modules totalled 48 MW, an increase of 14 percent over 1989's sales. (Photovoltaic Insider's Report, Jan., Feb., March 1991)

.14 Figure 1-4-1 shows estimates of the distribution of the photovoltaic market by type of application. (Miller and Rupnow, 1991). The figure indicates that from 1990 to 1995 substantial growth is forecast for the use of photovoltaics in utility power systems.

***Figure 1-4-1: Distribution of Photovoltaic Market by Type of Application [Miller and Rupnow, 1991]***

| Year | 1990 | 1995 |
|---|---|---|
| Remote location equipment | 37% | 40% |
| Calculators, instrumentation | 26% | 15% |
| Industrial, commercial power systems | 14% | 18% |
| Utility power systems | 7% | 19% |
| All other | 16% | 8% |
| Total | 100% | 100% |

.15 The largest photovoltaic power plant to date was the 6.5 MW ARCO (now Siemens Solar) station at Carrisa Plains, California. Carrisa Plains was first operated in 1983, used flat-plate two-axis tracking technology and was connected to the Pacific Gas & Electric grid. The plant is now being dismantled by a new owner who is selling the components for reuse in small distributed applications.

.16 Some examples of large photovoltaic demonstration projects in other parts of the world include Rokko Island, a 1 MW installation in Japan; Pellworm, a 300 kW installation and Kobern-Gondorf, a 340 kW installation, both in Germany.

.17 Photovoltaics for Utility Scale Applications (PVUSA) is a U.S. program initiated in 1986 with the following goals (Hester et al., 1990):

"To assess promising U.S. photovoltaic technologies in a side-by-side utility setting; looking towards cost-effective commercialization by the mid 1990s; and to create a program to transfer photovoltaic knowledge between government, the photovoltaic industry, and U.S. Utilities."

.18 Phase 1 of PVUSA is underway at a total project cost of approximately $19 million and involves installation of various "Emerging Module Technologies" each of 20 kW, nominal.

.19 Phase 2 of PVUSA will involve installation of "Utility Scalable" systems of 200 kW to 400 kW capacity.

.20 While there are still plans for some large scale projects, notably a 20 MW plant near Sacramento, emphasis has shifted to smaller applications more suited to decentralized use in remote locations.

### *Canadian Experience: Photovoltaic*

.21 Photovoltaic installations in Canada total about 500 kW.

.22 The Canadian Coast Guard is the largest user with some 3000 installations ranging from 10 to 1200 watts powering lighthouses, radio beacons and other navigational devices.

.23 Units up to 2 kW are employed by rail and telecommunication companies to power remote radio repeater stations.

.24 Canadian R&D is focusing on hybrid photovoltaic/diesel electric systems in which solar power is used to reduce diesel fuel consumption in remote locations.

.25 Farmers and cottagers are now able to purchase photovoltaic systems for on site applications including lighting and water pumping.

.26 The Canadian Photovoltaic Industries Association lists 47 domestic suppliers of photovoltaic equipment and information.

*Ontario/Ontario Hydro Experience: Photovoltaic*

.27 Photovoltaic technology has been operating in Ontario for over 10 years.

.28 Ontario Hydro installed the first large system in Canada, a 2.4 kW power supply for an air quality monitoring station near Atikokan in 1981. The system operated until 1989 when the monitoring station was shut down.

.29 Ontario Hydro installed the first utility interactive residential system near Toronto in 1983. This photovoltaic demonstration system is still in use at the Kortright Centre for Conservation, near Kleinburg.

.30 There are now three photovoltaic systems tied to Ontario's electricity grid – the 2 kW system at Kortright, a 4 kW system installed at Ontario Place by the Ministry of Energy, and a privately owned 5 kW system installed at a Mississauga residence.

.31 Ontario Hydro designed and operates Canada's largest facility, a 10 kW hybrid plant at Big Trout Lake. This system, which came into service in 1986, is connected to and supplements the remote community's diesel power grid.

.32 Figure 1-4-2 shows the Big Trout Lake installation.

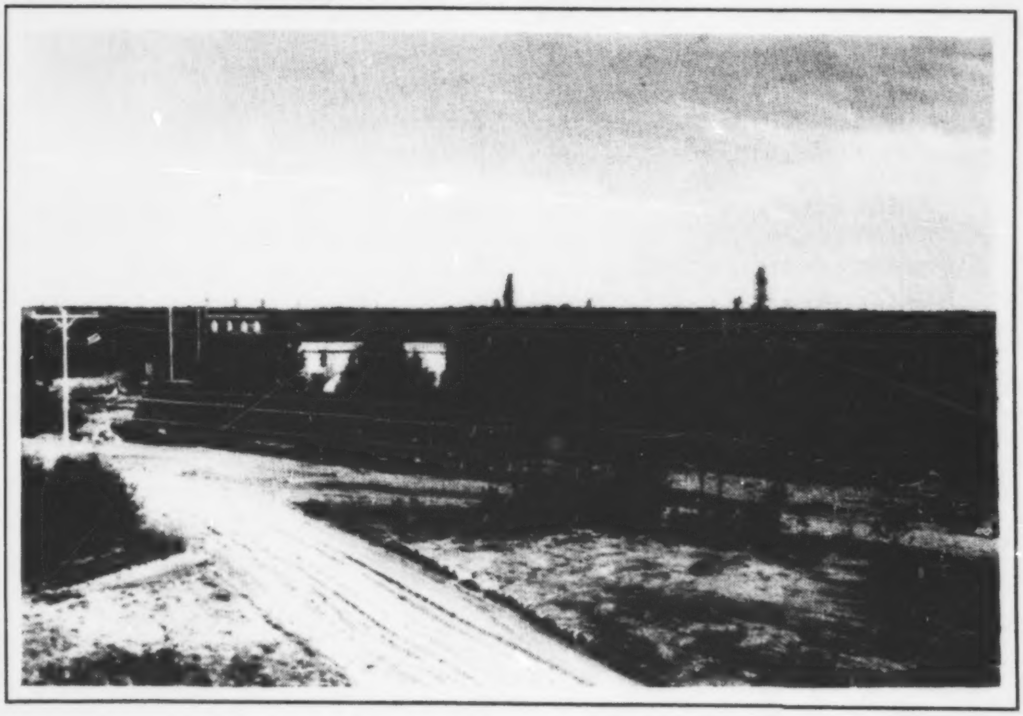
.33 Ontario Hydro is currently developing small photovoltaic units for water pumping and lake aeration applications There is also interest in using photovoltaics to offset some of the energy required for air conditioning.

### 1-4-2 Solar Thermal Electric Technologies

*World Experience: Solar Thermal*

.1 Solar thermal electric technology has been demonstrated in many areas of the world. About 90 percent of the world's solar electricity is generated in California. By 1994 as much as 600 MW of solar thermal electric plants may be installed in Southern California alone.

***Figure 1-4-2: Ontario Hydro's Big Trout Lake Photovoltaic Installation***



.2 The following sections describe some of the key installations of central receivers, parabolic troughs, parabolic dishes, and solar ponds.

### *Central Receivers*

.3 Central receivers require complex and bulky equipment which is best suited to development at relatively large, centralized generating sites.

.4 The largest central receiver to date, the 10 MW plant near Barstow, California, achieved up to 10 percent capacity factor and a peak instantaneous output of 11.7 MW.

.5 From 1982 to 1988 Southern California Edison operated this "Solar Power Tower" using motor-driven heliostats to track the sun. The "Solar Power Tower", was a demonstration plant and is no longer in service.

.6 Other smaller central receiver plants have been installed as demonstration projects in New Mexico (5 MW) and Spain (500 kW).

### *Parabolic Dishes*

.7 Parabolic dish technology is presently at the field experiment stage.

.8 Parabolic dishes produce higher temperatures and therefore operate at higher thermal efficiencies than some other solar thermal technologies; however, at present those advantages are offset by their higher cost.

.9 Dishes are relatively more difficult and expensive to construct because of their shape and because they require more accurate and sophisticated sun-tracking mechanisms.

.10 Parabolic dish systems have been operated experimentally in utility settings in Georgia and southern California.

.11 Recently, experimental dish-mounted 25 kW generators using Stirling engines have demonstrated efficiencies of 30 percent.

### *Parabolic Troughs*

.12 Parabolic troughs are the dominant solar thermal technology. They are simpler to construct and less costly than other technologies at present.

.13 Parabolic trough technology is now commercial and accounts for almost all of the world's solar thermal electric generation.

.14 About 90 percent of the world's solar electricity is generated by Solar Electric Generating Stations (SEGS) designed and operated by Luz International Limited of California. In all there are nine Luz stations in operation, ranging from 14 MW to 80 MW, and four under development. (Lother and Kearney, May/June 1991). Luz SEGS plants contribute 354 MW to the Southern California Edison system in California, with an additional 300 MW planned by 1994. (Solar Today, 1991)

.15 Figure 1-4-3 shows a schematic of the Luz SEGS.

### *Solar Ponds*

.16 The essential conditions which permit the use of solar pond thermal technology (a high proportion of direct radiation, a high solar angle, and relatively warm weather) do not favour use of this technology in Ontario.

.17 Solar ponds have been generating electricity in Israel for over 10 years. The latest project located near the Dead Sea produces up to 5 MW of electricity during peak demand periods.

.18 Solar pond projects for electricity generation or space heating are also underway in the U.S., Australia, Mexico, India, Italy, Argentina, Japan, Portugal, Qatar and Kuwait.

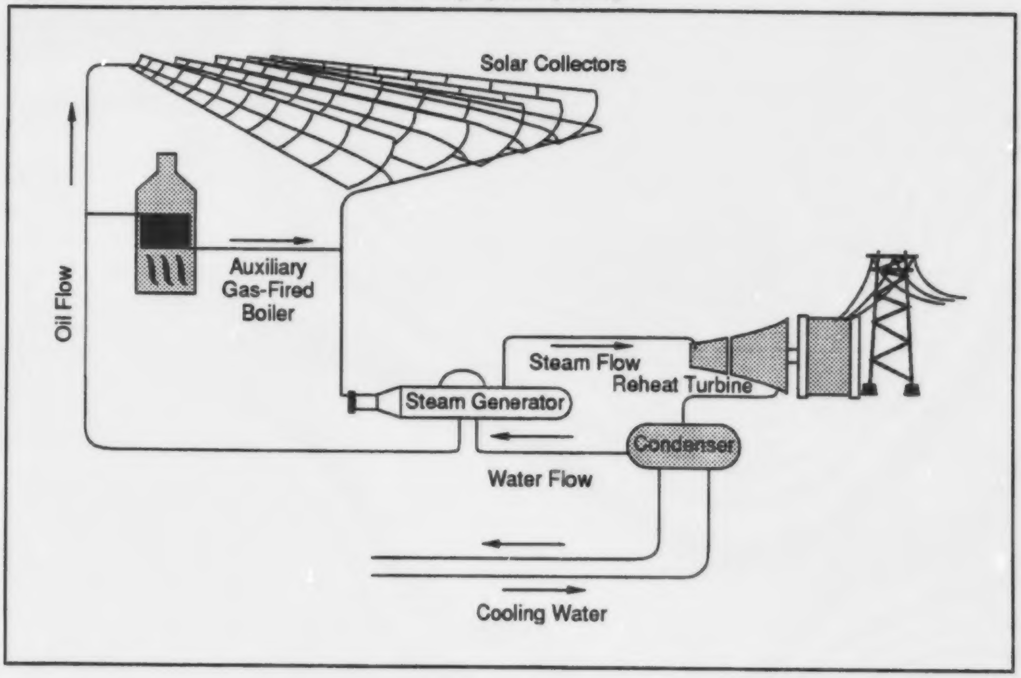
.19 The El Paso Solar Pond which began operation in 1986 was the first U.S. plant to generate electricity. The plant has a rating of 70 kW.

### *Canadian/Ontario Hydro Experience: Solar Thermal*

.20 No solar thermal electric systems have been operated in Ontario.

.21 Ontario Hydro is not aware of any proposals for the use of this technology in Ontario at this time.

*Figure 1-4-3: The LUZ Solar Energy Generating System (SEGS)*



## 1-5 Potential System Application

### 1-5-1 Photovoltaic

.1 Cost is the critical factor limiting the application of photovoltaics.

.2 The price for modules has shown a steady decrease of approximately 15 percent per year over the ten years up to 1989. For example, photovoltaic modules purchased in 1989 by Ontario Hydro for a remote community project cost $6.66 per peak watt; modules purchased in 1980 for one of the first projects ranged in price from $24 to $32 per peak watt.

.3 The Electric Power Research Institute (EPRI), estimates that capital costs below U.S. $1/watt (at efficiencies of 15 percent) will be necessary for photovoltaic technology to produce electricity at U.S. 6 to 8 ¢/kWh. (EPRI, 1989)

.4 In Ontario's climate, with a relatively low proportion of direct sunlight, flat plate photovoltaic arrays are the most appropriate. The most cost effective applications of photovoltaics will be in the remote north where the cost of conventional electricity is very high.

.5 Fixed arrays using single and multi-crystal photovoltaic modules will dominate northern Ontario applications because of their reliability and simplicity.

.6 Utility interactive photovoltaic systems are expected to be smaller decentralized installations as opposed to large central stations, since sunlight is a dispersed source of energy and photovoltaic systems are modular.

.7 Modularity would enable: (1) the addition of small blocks of capacity to match growth in demand, and (2) dispersal of the units to reduce transmission costs (within the siting limits discussed above).

.8 In Ontario, generation is most likely to come from dispersed photovoltaic power sources with the arrays incorporated into the building structure; roof-tile and picture window photovoltaic modules are presently being introduced on the market. An appropriate use would be to offset some of the energy required for air conditioning.

.9 Photovoltaic options are non-dispatchable. As discussed in Part 1, Section 1-7, issues surrounding the impact on electricity systems of the use of many non-dispatchable sources of electricity must be studied and resolved before photovoltaic options can achieve high penetration levels.

### 1-5-2 Solar Thermal Electric Technologies

.1 Solar thermal electric systems are more suited to sunny environments such as those of the American southwest, where peak insolation (maximum sunlight) also coincides with peak electricity demands (e.g., air conditioning requirements).

.2 Insolation conditions in Ontario do not favour solar thermal electric technologies.

### 1-6 Environmental Considerations

.1 This section of the review discusses environmental considerations, both natural and social, associated with solar energy technologies.

.2 While there are environmental concerns and potential safety hazards associated with the production of solar energy systems, the management of environmental effects associated with prefabrication are assumed to be included in the price of the items, and are not addressed in detail.

### 1-6-1 Environmental Considerations: Photovoltaics

.1 This section discusses environmental considerations, both natural and social, associated with photovoltaics.

.2 The generation of electricity by photovoltaics is considered to be an environmentally promising technology.

### 1-6-1-1 Natural Environment: Photovoltaics

.1 This section discusses environmental issues associated with photovoltaics and their impact on the natural environment, under the headings of air, land and water.

.2 The photovoltaic field is evolving rapidly. Environmental impacts will depend partially on the choice of technology and materials.

*Air*

.3 The photovoltaic cells produce no emissions during operation.

*Land*

.4 The need to acquire land for photovoltaic electricity generation would depend on whether a centralized or decentralized approach were to be used. Decentralized photovoltaic systems utilizing rooftops of houses and industrial buildings would avoid the need for "new" land. From a land use point of view decentralized photovoltaic systems are clearly preferable to centralized facilities.

.5 The land required for a centralized system would be substantial. The collector surface area required for photovoltaics is a function of cell efficiency. The efficiency of commercial photovoltaic cells has increased since the 1970s and is now approximately 11 to 14 percent. Increases in photovoltaic efficiency decrease the land and materials requirements.

.6 A centralized facility designed to produce, for example, 5 percent of Ontario's 137 TWh load for 1990 would require about 225 $km^2$ of land area. Vegetation would have to be controlled and kept low. Compatible land uses could be found (e.g., grazing, parking, roads).

.7 Construction activities associated with centralized facilities may require precautions to minimize soil compaction and erosion.

.8 Decommissioning of photovoltaic facilities, whether central or distributed, would require solid waste disposal. Photovoltaic modules may be amenable to reuse in smaller systems. Cells containing materials such as gallium arsenide may present recycling difficulties and might have to be disposed of as hazardous materials.

*Water*

.9 The cells produce no aquatic emissions during operation.

.10 Construction activities associated with centralized photovoltaic systems may require precautions to minimize erosion and siltation of local water bodies.

*Summary*

.11 Photovoltaic electricity generation is an environmentally promising technology. Issues include high levels of land use for centralized facilities and the use of toxic materials in some technologies (e.g., gallium arsenide). Decentralized photovoltaic electricity generation is very attractive relative to centralized generation in terms of land use.

### 1-6-1-2 Social Environment: Photovoltaics

.1 This sections discusses issues associated with photovoltaics and their impact on the social environment under the headings of socio-economic effects and societal considerations.

*Socio-Economic Effects*

.2 There is now presently a small industrial infrastructure in place to assemble photovoltaic electricity generation modules in Ontario. Without specific policies to stimulate the development of a provincial photovoltaic manufacturing industry, regional employment and economic development is expected to be limited to activities and spinoffs associated with the assembly, installation and maintenance of photovoltaic systems.

.3 With socio-economic incentives, the manufacture, installation and servicing (to the extent required) of photovoltaics may stimulate minor additional provincial level employment and short-term regional employment.

.4 Decentralized solar options may provide positive community effects in remote areas such as remote settlements or cottages in northern areas not serviced by Ontario Hydro.

.5 If a large centralized photovoltaic facility were to be installed, the land requirement could result in disruption and displacement effects for local residents. However, decentralized photovoltaic systems using rooftops of existing buildings would avoid this impact.

*Societal Considerations*

.6 Environmentally attractive features of photovoltaics have resulted in a significant degree of social acceptance of this energy option. (Goldfarb, 1986). Solar energy is a renewable energy source.

.7 Photovoltaics have resulted in a significant degree of social acceptance of this energy option. (Goldfarb, 1986). Solar energy is a renewable energy source.

.8 Decentralized photovoltaic systems may require additional local legislation to ensure adequate provision for sunlight protection and the minimization of visual impacts.

### 1-6-2 Environmental Considerations: Solar Thermal Electric

.1 This section discusses environmental considerations, both natural and social, associated with solar thermal electric technology.

### 1-6-2-1 Natural Environment: Solar Thermal Electric

.1 This section discusses environmental and safety issues associated with solar thermal electric technologies and their impact on the natural environment, under the headings of air, land, water and other.

*Air*

.2 If a centralized facility used cooling towers, the potential would exist for concerns regarding fog and ice formation in the vicinity of the plant. Dry cooling systems can be used rather than cooling towers.

*Land*

.3 The most discussed environmental concern associated with solar thermal generation of electricity is the high land use requirement.

.4 For example, a solar thermal facility in the southwestern U.S. would require approximately 2.1 hectares per megawatt. (Lotker and Kearney, 1991). Lower solar insolation values in Ontario, resulting in large part from lower levels of direct sunlight, would increase this requirement.

.5 Vegetation may have to be controlled to prevent shading. Depending on original land use, the terrestrial ecosystem could be significantly altered, affecting habitat for vegetation and wildlife.

*Water*

.6 Dry cooling systems could be installed at smaller generating stations of the sizes envisaged. If once-through cooling were used however, heat would be emitted to the aquatic environment.

.7 Since the conversion efficiencies for solar thermal electric facilities are comparable to traditional fossil fuelled generation facilities, water requirements would be similar to once-through cooling requirements for fossil-fuelled facilities. (Power, 1990)

*Other*

.8 Fluids used for heat exchange and storage include sodium, organic oils and molten salts. Normal operation would result in small releases, which could increase in the event of accidents.

.9 Decommissioning of solar thermal electric facilities would require solid waste disposal. Some material may be amenable for recycling or reuse. Other materials (e.g., some heat exchange fluids) may require disposal as hazardous materials.

### 1-6-2-2 Social Environment: Solar Thermal Electric

.1 This section discusses issues associated with solar thermal electric technologies and their impact on the social environment under the headings of socio-economic effects and societal considerations.

*Socio-Economic Effects*

.2 Given that solar thermal technologies are more suited to sunny American southwest climatic conditions than to Ontario, the potential for their implementation is limited. However, should technical breakthroughs in the technology occur, technical and financial support for solar thermal could stimulate provincial economic development. Solar thermal technologies could utilize a high Canadian content in their manufacture. Maintenance requirements could also increase employment opportunities.

.3 Some of the social and community impacts associated with centralized solar thermal facilities could include equipment purchases, disruption and displacement effects as a result of the need for large land areas, local effects of cooling facilities and construction impacts.

*Societal Considerations*

.4 Environmentally attractive features of solar thermal facilities have resulted in a significant degree of social acceptance of this energy option. (Goldfarb, 1986). Solar energy is a renewable energy source.

### 1-7 Operational Considerations

.1 Photovoltaic modules require little maintenance once installed. They require no fuelling and there are no moving parts. Maintenance for one of the larger installations, the one megawatt plant at Hesperia, California, consisted of once weekly site visits by an engineer. Otherwise the plant operated unattended.

.2 Future photovoltaic systems would take advantage of the low maintenance and modularity features. Photovoltaic systems could be utilized as dispersed power sources located close to the load thereby reducing peak demands on utility distribution systems. These power plants could be incorporated unobtrusively into or on the structure of the building they serve. Buildings such as industrial complexes or shopping malls have adequate roof area for large photovoltaic arrays.

.3 Since the power source is the sun the power output from a photovoltaic plant cannot easily be controlled. The capacity factor of the plant depends on the availability of sunlight. In Ontario's environment the annual average capacity factor will not exceed 15 percent. The best use of photovoltaics is in applications which provide a good match between the availability of solar power and the need for power (e.g., air conditioning).

### 1-8 Development Issues

.1 The major barrier to the widespread implementation of photovoltaics is its current high cost. Costs have decreased greatly over the past decade but not as much as projected. Costs of the predominant crystalline and semi-crystalline technologies are projected to decrease further due to improved design and manufacturing methods.

.2 Efficiencies of single crystal silicon cells and other exotic materials have reached impressive levels (more than 20 percent), both in the laboratory and in the field. Technological breakthroughs which greatly reduce costs are quite possible.

.3 Thin film technologies which involve the deposition of very thin (one micrometre) layers of semiconducting material on an inexpensive substrate such as glass, metal or ceramic continue to be developed. Thin film photovoltaic systems are currently manufactured using expensive vacuum deposition techniques. Less expensive methods being investigated include electroplating, spray pyrolysis and silk-screen printing. Methods of incorporating photovoltaic coatings on building materials such as windows and roofs are also being investigated.

.4 Balance of system costs (which include installation, mounting supports and power conditioning of the photovoltaic output to interface with the AC systems) are a significant fraction of the cost of photovoltaic systems. Some cost reductions may be expected as the market increases.

## 1-9 Options Costed

.1 Based on the above assessment, the following two photovoltaic options are selected as representative of typical installations in order to prepare representative costs.

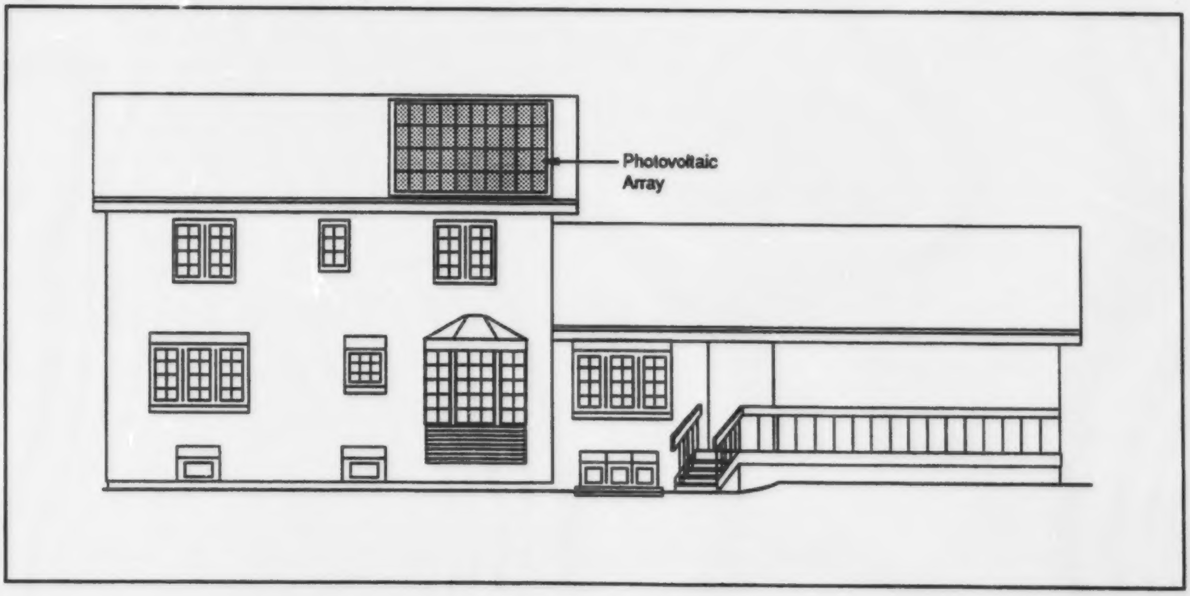
### 1-9-1 Option 1: 2 kW Utility Interactive Photovoltaic System

.1 This system, for home use, consists of approximately 14 square metres of photovoltaic array (14 percent efficiency) with the DC output connected to the AC residential service entrance via a line-commutated inverter. It is assumed the array would be roof mounted on a typical residence and would consist of single or multi-crystal modules. This option is illustrated in Figure 1-9-1.

.2 Why select fixed flat plate collectors? The rationale for using fixed flat plate collectors is based on the fact that a large portion of sunlight in Ontario is diffuse light. Focusing designs will not capture this energy and complex tracking mechanisms would not be cost effective.

.3 Why is the array roof mounted? Roof mounting eliminates the need for additional land. This feature is particularly important in urban installations. The added benefit is that the power supply is close to the load.

*Figure 1-9-1: Photovoltaics – 2kW Option*



.4 Why select single or multi-crystal silicon cells? Silicon crystal technology has demonstrated extremely reliable operation over the past decade. Other technologies, notably amorphous silicon or other thin film cells, may have long term potential, especially in reducing cost, but so far have failed to perform to expectations. Given recent advances in manufacturing techniques many experts believe near term field applications will be dominated by silicon crystal technology.

.5 Why select a 2 kW system? While there is a great variation in house designs, 14 square metres would be the average array size that could be unobtrusively installed on the southern half of a residential roof. Some houses could possibly incorporate larger systems; others, because of orientation and shading, may not be suitable for any solar installation.

.6 Why select a line-commutated inverter? In addition to being simple, reliable and low cost, line-commutated inverters shut down when there is no power from the grid, thus inherently meeting a prime utility safety requirement.

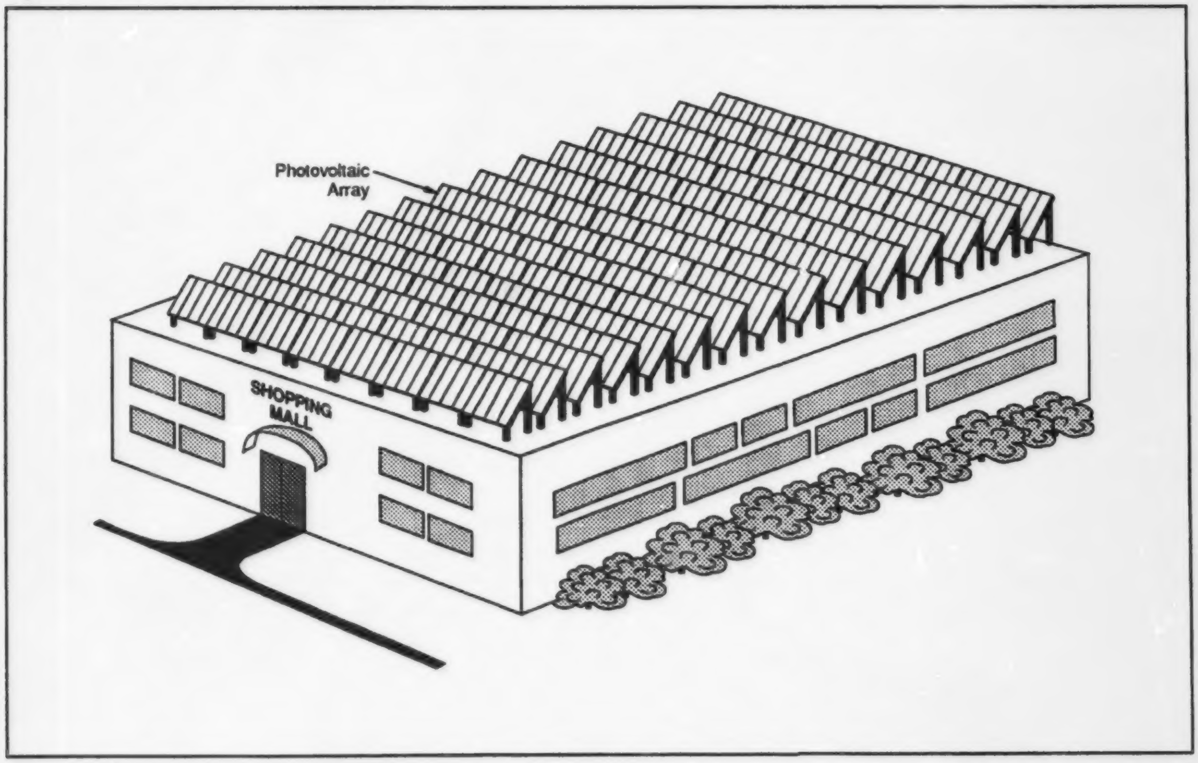
.7 Are there any special considerations for a roof-mounted residential photovoltaic power supply? If roof-mounted solar systems are widely adopted, issues such as ownership, metering and solar rights (shadows from neighbours) will have to be resolved.

### 1-9-2 Option 2: 100 kW Utility Interactive Photovoltaic System

.1 This photovoltaic system consists of approximately 700 square meters of photovoltaic array (14 percent efficiency) with the DC output connected to the AC utility distribution system via a line-commutated inverter. The array would be roof-mounted on an industrial or shopping mall building structure and would consist of conventional single or multi-crystal silicon flat plate collectors mounted in a fixed position. This option is shown schematically in Figure 1-9-2.

.2 The rationale for using fixed flat plate collectors was discussed above in Section 1-3-1.

*Figure 1-9-2: Photovoltaics – 100kW Option*



.3 Why select a 100 kW system? The 100 kW rating is nominal. Since photovoltaic systems are modular any size can be selected. However, since both the fuel (sunlight) and most electrical loads are dispersed, there are no advantages to operating large central photovoltaic power plants.

.4 Are there any special advantages to be gained from a 100 kW roof-mounted fixed array system? The 100 kW rating represents the size that could be readily installed on the roof of a typical 35 m x 35 m commercial building in a conventional array row format (approximately 15 rows of fixed arrays with a height of 2 m). The output of the photovoltaic power supply could be used to reduce the peak load requirements on local utility distribution systems.

## 1-10 Costs and Performance

.1 This section discusses the costs and performance assumptions used to assess the 2 kW and 100 kW photovoltaic options. The measure used to assess the photovoltaic options is the cost/benefit ratio previously discussed in Part 1, Section 1-7.

.2 For the purposes of this assessment, the two options are assumed to be located in Toronto, Ontario.

### 1-10-1 Performance Assumptions

.1 Figure 1-10-1 below summarizes the performance assumptions used in evaluating the photovoltaic options.

.2 The useful life of 30 years is a judgement, and is not based on experience.

.3 The annual capacity factor of 12 percent is based on solar insolation data for Toronto, Ontario.

### 1-10-2 Calculation of Benefits: Photovoltaics

.1 The benefits of photovoltaic installations to an electricity system are two-fold – the value of the energy produced by the installation and the value of the "capacity" provided by that installation to the system. This latter benefit, known as the "capacity credit", is discussed in Part 1, Section 1-7 of this review. Photovoltaic options are also eligible for the 10 percent "renewables" credit discussed in the same section.

.2 In addition, both of the photovoltaic options assessed here are eligible for credits for avoiding transmission and distribution costs and losses. These credits are discussed below.

*Value of Energy Produced*

.3 Estimates of the total annual energy and the daily and seasonal variation in the energy production are required to calculate the benefits of the energy produced by a photovoltaic installation to an electricity system or owner/operator.

.4 There are four categories of energy known as summer peak energy, winter peak energy, summer off-peak energy and winter off-peak energy, each of which has a different value to an electricity system.

.5 Environment Canada solar insolation data for Toronto were used to calculate the energy which would be produced by each photovoltaic option during each day and during each month of the year. This energy production was then split into the four categories of energy discussed above. The value of this energy was then calculated using Ontario Hydro incremental system values of energy.

.6 The estimated energy production from each of the two options, split into the four categories indicated, as well as the present value (PV) of this energy in 1991 dollars, are shown in Figure 1-10-2.

***Figure 1-10-1: Photovoltaic Performance Assumptions***

| Option | Description | Useful Life (yrs.) | Annual Capacity Factor (%) | Annual Energy Production (kWh) |
|---|---|---|---|---|
| 1 | 2 kW | 30 | 12 | 2100 |
| 2 | 100 kW | 30 | 12 | 105120 |

*Figure 1-10-2: Value of Energy Produced – Photovoltaic Installations*

| | Option 1: 2 kW | Option 2: 100 kW |
|---|---|---|
| Winter Peak Energy (kWh) | 535 | 26,790 |
| Winter Off Peak Energy (kWh) | 244 | 12,230 |
| Summer Peak Energy (kWh) | 918 | 45,910 |
| Summer Off Peak Energy (kWh) | 403 | 20,190 |
| Total Energy Produced (kWh) | 2,100 | 105,120 |
| Present Value of Energy ($ 1991) | 674 | 33,691 |

.7 Note that, as would be expected, the largest proportion of the energy produced by a photovoltaic installation occurs during the summer peak period when there is the most sunlight.

### *Capacity Credit*

.8 Photovoltaic installations are considered to be eligible for a partial capacity credit since there is a correlation between the time when the sun is most likely to be shining and the time when system peak demand is likely to occur. This benefit is estimated at 20 percent of the nominal rating based the likelihood of energy production from photovoltaic installations being available at the time when system peak demand occurs.

.9 The present value of the capacity credit for Option 1 (2 kW) is estimated to be $370.

.10 The present value of the capacity credit for Option 2 (100 kW) is estimated to be $18,485.

### *Renewables Credit*

.11 Photovoltaic installations would be eligible for a "renewables credit" of 10 percent of the sum of the benefits (energy and capacity) produced by the option.

.12 For Option 1 (2 kW) this credit is $104 or 10 percent of the total of the capacity and energy benefits calculated above, ($674 energy + $370 capacity = $1,044).

.13 For Option 2 (100 kW) this credit is $5,218.

### *Transmission and Distribution Credits*

.14 Included in the present values of capacity and energy, for both options, are credits for avoiding bulk electricity system costs ($12/kW/yr), regional supply system costs ($7/kW/yr), distribution system costs ($10/kW/yr), and a credit for avoiding transmission and distribution losses (7 percent of the total value of energy and capacity).

### *Summary of Benefits*

.15 The present values of the benefits for the two photovoltaic options are summarized below in Figure 1-10-3.

*Figure 1-10-3: Summary of Benefits – Photovoltaic Installations ($ 1991)*

| | Option 1: 2 kW | Option 2: 100 kW |
|---|---|---|
| Energy Benefit | 674 | 33,691 |
| Capacity Credit | 370 | 18,485 |
| Renewables Credit | 104 | 5,218 |
| Total Benefits | 1,148 | 57,394 |

## 1-10-3 Cost Estimates

.1 As discussed in Part 1, Section 1-7, the cost estimates for photovoltaic installations are developed based mainly on surveys of manufacturers and on industry surveys regarding costs and cost trends. Ontario Hydro's experience with photovoltaic installations is limited to demonstration projects.

.2 Cost estimates are based on the most current information available to Ontario Hydro. The costs are intended to provide an indication of a range of costs and not a definitive estimate of the cost of each option.

.3 The cost estimates for the photovoltaic options are presented as both current costs and projected costs in the year 2000.

.4 As the fuel for this option is the sun, there are no fuelling costs.

.5 Capital and OM&A cost estimates for the photovoltaic options are shown in Figure 1-10-4. As is true of all photovoltaic installations, the capital cost of the equipment is the overriding cost factor.

*Present Value of Costs*

.6 The present values of the costs of the two photovoltaic options are summarized in Figure 1-10-5.

### 1-10-4 Net Present Value and Cost/Benefit Ratio Summary

.1 The present values of the benefits, the present values of the costs as well as the net present values and cost/benefit ratios for the photovoltaic options are summarized in Figure 1-10-6.

.2 The results show that, for the two options analyzed, the cost/benefit ratio is estimated to be greater than one (negative net present values) for both options, for both 1991 costs and projected year 2000 costs.

***Figure 1-10-4: Cost Estimates – Photovoltaic Options***

| Cost Component | Option 1 – 2 kW | | Option 2 – 100 kW | |
|---|---|---|---|---|
| | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs |
| Initial Capital ($/kw) | 8,200 | 2,500 | 7,200 | 2,200 |
| Later Capital ($/kW/yr) | 0 | 0 | 0.67 | 0.67 |
| OM&A (¢/kWh) | 0.6 | 0.6 | 0.6 | 0.6 |

***Figure 1-10-5: Present Value of Costs – Photovoltaic Options (000s $ 1991)***

| Cost Component | Option 1 – 2 kW | | Option 2 – 100 kW | |
|---|---|---|---|---|
| | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs |
| Total Capital | 8.7 | 2.7 | 380.4 | 116.4 |
| OM&A | 0.1 | 0.1 | 6.4 | 6.4 |
| Total | 8.8 | 2.8 | 386.8 | 122.8 |

***Figure 1-10-6: Summary of Costs and Benefits – Photovoltaic Options***

| Costs and Benefits | Option 1 – 2 kW | | Option 2 – 100 kW | |
|---|---|---|---|---|
| | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs |
| PV of Costs (000s $ 1991) | 8.8 | 2.8 | 386.8 | 122.8 |
| PV of Benefits (000s $ 1991) | 1.1 | 1.1 | 57.4 | 57.4 |
| Net PV (000s $ 1991) | -7.7 | -1.7 | -329.4 | -65.4 |
| Cost/Benefit Ratio | 7.7 | 2.4 | 6.7 | 2.1 |
| LUEC (¢/kWh)* | 51.3 | 16.2 | 45.2 | 14.4 |

* LUEC is provided for information only and should be interpreted with care. As discussed in Part 1, Section 1-7, LUEC is not the appropriate measure with which to assess photovoltaic options.

## 1-10-5 Sensitivities

.1 For each option, the sensitivities of the net present value and the cost/benefit ratio to variations in the values of the individual cost components, in economic factors and in performance, are presented. Sensitivity analysis provides an indication of the variability of the net present value and the cost/benefit ratio to changes in cost and performance assumptions.

.2 The cost estimates for photovoltaic installations are subject to large uncertainties, particularly when considering projected year 2000 costs. These large uncertainties are reflected in the uncertainty ranges.

.3 The sensitivity ranges are not intended to reflect a particular confidence level. The level of information available does not lend itself to such a detailed analysis. They simply represent Ontario Hydro's judgement on the possible variation of these factors.

.4 Figures 1-10-7 and 1-10-8 show the sensitivity ranges selected for costs and performance respectively, and the effect of those ranges on the net present value and cost/benefit ratios for the two options assessed.

*Figure 1-10-7: Cost Component Sensitivities – Photovoltaic Options*

| | Point Estimate | | Range Assumed (%) | | Sensitivity (%) * | |
|---|---|---|---|---|---|---|
| | Cost | Present Value (000s $) | Lower | Upper | Lower | Upper |
| **Option 1: 1991 Costs** | | | | | | |
| Capital | 8200 $/kW | 8.7 | -20 | +20 | -19.7 | +19.7 |
| OM&A | 0.6 ¢/kWh | 0.1 | -10 | +15 | -0.1 | +0.2 |
| Total | N/A | 8.8 | N/A | N/A | -19.8(1) | +19.9(1) |
| **Option 1: 2000 Costs** | | | | | | |
| Capital | 2500 $/kW | 2.7 | -10 | +30 | -9.5 | +28.6 |
| OM&A | 0.6 ¢/kWh | 0.1 | -10 | +15 | -0.5 | +0.7 |
| Total | N/A | 2.8 | N/A | N/A | -10.0(1) | +29.3(1) |
| **Option 2: 1991 Costs** | | | | | | |
| Capital | 7220 $/kW | 380.4 | -20 | +20 | -19.7 | +19.7 |
| OM&A | 0.6 ¢/kWh | 6.4 | -10 | +15 | -0.2 | +0.2 |
| Total | | 386.8 | N/A | N/A | -19.9(1) | +19.9(1) |
| **Option 2: 2000 Costs** | | | | | | |
| Capital | 2220 $/kW | 116.4 | -10 | +30 | -9.5 | +28.4 |
| OM&A | 0.6 ¢/kWh | 6.4 | -10 | +15 | -0.5 | +0.8 |
| Total | N/A | 122.8 | N/A | N/A | -10.0(1) | +29.4(1) |

* Percentage change in total present value of costs for each option.

(1) Total sensitivities are calculated as if all cost components are fully dependent.

*Figure 1-10-8: Performance Sensitivities – Photovoltaic Options*

| Factor | Point Estimate | Present Value (000s $) | Range Assumed | | Sensitivity (%) * | |
|---|---|---|---|---|---|---|
| | | | Lower | Upper | Lower | Upper |
| Option 1: | | | | | | |
| Annual Capacity Factor | 12% | 0.67 | 14% | 10% | 10.8 | -10.8 |
| Capacity Credit (% of rating) | 20% | 0.37 | 25% | 0% | 8.9 | -35.4 |
| Life (years) | 30 | N/A | 35 | 25 | 6.5 | -8.1 |
| Renewables Credit | 10% | 0.10 | 10% | 10% | 0.0 | 0.0 |
| Total Benefit | | 1.14 | | | | |
| Option 2: | | | | | | |
| Annual Capacity Factor | 12% | 33.7 | 14% | 10% | 10.8 | -10.8 |
| Capacity Credit (% of rating) | 20% | 18.5 | 25% | 0% | 8.9 | -35.4 |
| Life (years) | 30 | N/A | 35 | 25 | 6.5 | -8.1 |
| Renewables Credit | 10% | 5.2 | 10% | 10% | 0.0 | 0.0 |
| Total Benefit | | 57.4 | | | | |

* Percentage change in total present value of benefits for each option.

.5 Given the assumptions in this report regarding costs and performance, the largest range of net present values and cost/benefit ratios for each option can be obtained by assuming that all cost components and performance factors are fully dependent. That is, if one cost component increases, all cost components are assumed to increase and all performance factors are assumed to decrease, and vice-versa. In this manner, an indication of the upper and lower ranges of the net present values and cost/benefit ratios for each option is obtained. These upper and lower estimates are shown in Figure 1-10-9.

*Figure 1-10-9: Overall Sensitivity – Photovoltaic Options (All Factors Dependent)*

| Option | Overall Sensitivity – Cost/Benefit Ratios | | |
|---|---|---|---|
| | Lower Estimate | Point Estimate | Upper Estimate |
| **Option 1:** | | | |
| 1991 Costs | 4.5 | 7.7 | 18.6 |
| 2000 Costs | 1.6 | 2.4 | 6.3 |
| **Option 2:** | | | |
| 1991 Costs | 4.0 | 6.7 | 15.7 |
| 2000 Costs | 1.4 | 2.1 | 5.4 |

### 1-10-6 Cost Summary

.1 This assessment of photovoltaic installations indicates that they are not currently economic sources of generation for the bulk electricity system in Ontario.

.2 This conclusion is based on cost/benefit ratios of greater than one (negative net present values) for the two photovoltaic options assessed. That is, capital and operating costs would not be recovered over the life of the options.

.3 When costs are projected to the year 2000 the results show that, although there is a large improvement, the cost/benefit ratios remain greater than one for both options.

## 1-11 Potential

### 1-11-1 Scenario Descriptions

.1 The potential for solar energy options is assessed under the three scenarios described in Part 1, Section 1-8. These scenario descriptions are repeated below.

*Scenario 1:* In this scenario, it is assumed that there is no improvement in current costs and technological status by the year 2000. The potential contribution by the year 2005 is assessed.

*Scenario 2:* In this scenario, an attempt is made to account for cost and technological improvements which may occur by the year 2000. Given these improvements, the potential contribution by the year 2005 is reassessed.

*Scenario 3:* The projections in this highly speculative scenario are based on assumptions that significant improvements in technology and costs could occur by the year 2010. The potential contribution by the year 2014 is assessed.

### 1-11-2 Projections of Potential

.1 Figure 1-11-1 shows the forecast of the potential contribution of photovoltaics under the three scenarios described above.

.2 Under Scenario 1 conditions, utility-connected photovoltaic systems are not cost effective. Photovoltaics are assumed to be applied in niche applications such as remote power supplies. The potential is projected to be limited to less than 1 MW by the year 2005.

.3 Scenario 2 is based on the expected photovoltaic potential that could be realized by the year 2005, assuming significant declines in photovoltaic costs by the year 2000. Under this scenario projections of potential remain the same as for Scenario 1.

.4 Scenario 3 is based on the expected photovoltaic potential that could be realized by the year 2014, assuming improvements in technology and further reductions in costs. In this case it is projected that as much as 100 MW of photovoltaics could be installed in the province by the year 2014.

***Figure 1-11-1: Forecast of Potential Contribution from Photovoltaic Technology***

| Scenario | Assumptions | Major Factors Affecting Potential | Cost Compared to Conventional Generation | Potential | | Potential Applications |
|---|---|---|---|---|---|---|
| | | | | MW | By Year | |
| 1 | • Current cost<br>• Current technology | • High capital cost | Above | < 1 | 2005 | • Niche<br>• Remote<br>• 2 kW units |
| 2 | • Capital cost of $1 - $2/W by year 2000 | | Above | < 1 | 2005 | • As above |
| 3 | • Improvement in technology<br>• Improvement in manufacturing cost resulting in capital costs of < $1/W | | Equal to or slightly above | 50 – 100 | 2014 | • Dispersed load-displacement application |

## 1-12 Overall Assessment

.1 Interest in photovoltaics for electricity generation results mainly from the use of a renewable energy source (sunlight) and negligible emissions to the environment during operation.

.2 Of the available methods of generating electricity from solar energy, the most promising for Ontario is the use of photovoltaics. Photovoltaic technology has been proven as a source of small-scale decentralized electricity generation.

.3 Cost estimates in this review indicate that photovoltaic technology is not currently economic for the production of electricity for the bulk electricity system in Ontario. Current costs are high; however, significant cost reductions are forecast by the year 2000.

.4 The current high cost of photovoltaics compared to conventional generation sources makes it an uneconomic alternative except in remote locations which do not have access to a central electrical grid.

.5 The first on-grid applications of photovoltaics would likely involve dispersed non-utility generation, with electricity being used primarily at the point of generation. Applications which provide a good match between the availability of solar power and the need for power will likely predominate. For example, photovoltaics could be used to offset some of the energy required for air conditioning.

.6 Sunlight is a diffuse energy resource requiring collection over large areas. However, photovoltaics can be installed unobtrusively on buildings thereby minimizing land requirements.

.7 Ontario Hydro sponsored surveys indicate that solar power is the second most favoured energy option behind hydro-electric development. Solar energy options are renewable and the social acceptance of solar power is high. Factors given for its support include solar power being perceived as the cheapest source of electricity, a renewable resource and the cleanest form of energy. (Goldfarb, 1986)

.8 Without specific policies to stimulate the development of a provincial photovoltaic manufacturing industry, regional employment and economic development are expected to be limited to activities associated with the assembling, installation and maintenance of photovoltaic systems.

.9 As discussed in Section 1-11, the potential contribution of photovoltaic technology to the electricity supply mix for Ontario could be as little as 1 MW by the year 2005 or as high as 100 MW by the year 2014 depending on cost and technological developments.

.10 The advantages of photovoltaic technology include:

- use of a renewable energy source,
- high social acceptance,
- no fuel costs,
- low maintenance costs,
- modularity, and
- minimal environmental impact, assuming roof-mounted installation.

.11 Barriers to large-scale implementation of photovoltaic technology include:

- high initial capital costs,
- intermittent availability of power, and
- limited manufacturing capacity at present.

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# Part 2: Technology Assessments

## Chapter 2: Wind

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## 2-1 Introduction

.1 As shown in Figure 2-1-1 Wind Energy Conversion Systems (WECS) fall into two general categories; WECS producing mechanical power and WECS generating electricity.

.2 WECS producing mechanical power is a technology which has been used for several centuries and can be used for such applications as water pumping.

.3 Figure 2-1-1 also shows that WECS designed for electricity production fall into two main classifications based on: (1) vertical, or (2) horizontal axis designs.

.4 The purpose of this paper is to describe existing and developing electric WECS technologies and to evaluate their potential for application in Ontario.

## 2-2 Fuel/Energy Source

.1 Winds are the air movements resulting from uneven heating of the earth's surface by the sun. Wind energy is therefore an indirect form of solar energy.

.2 Figure 2-2-1 illustrates mean wind speeds in Canada.

.3 Figure 2-2-2 illustrates mean wind speeds in Ontario.

.4 Ontario is not considered to be a windy area since average speeds range from less than 10 km/h to about 20 km/h. Wind speeds, however, are influenced by local topography and ground cover, as well as height above ground level, and are therefore very site specific.

.5 Because energy production by a wind turbine is extremely sensitive to wind speed (see section 2-3, below), general meteorological maps such as Figures 2-2-1 and 2-2-2 should not be used to assess the wind energy potential of specific sites. It is essential that potential wind energy generation sites be evaluated by accurate collection of wind data at representative locations and heights.

.6 Ontario's windiest sites are located along the Hudson Bay coastline and along the westward facing shores of the Great Lakes.

.7 Wind is an intermittent energy source and may vary greatly over short time periods as illustrated by the examples given below.

*Figure 2-1-1: Wind Energy Conversion Systems*

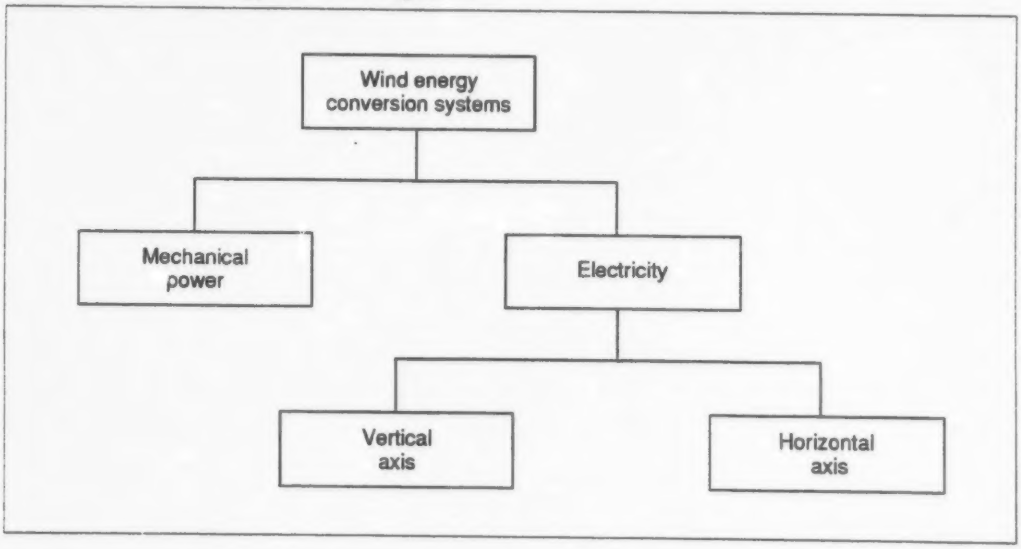

***Figure 2-2-1: Mean Wind Speed Map of Canada (Wind Speeds in km/h)***
***[Courtesy, Environment Canada]***

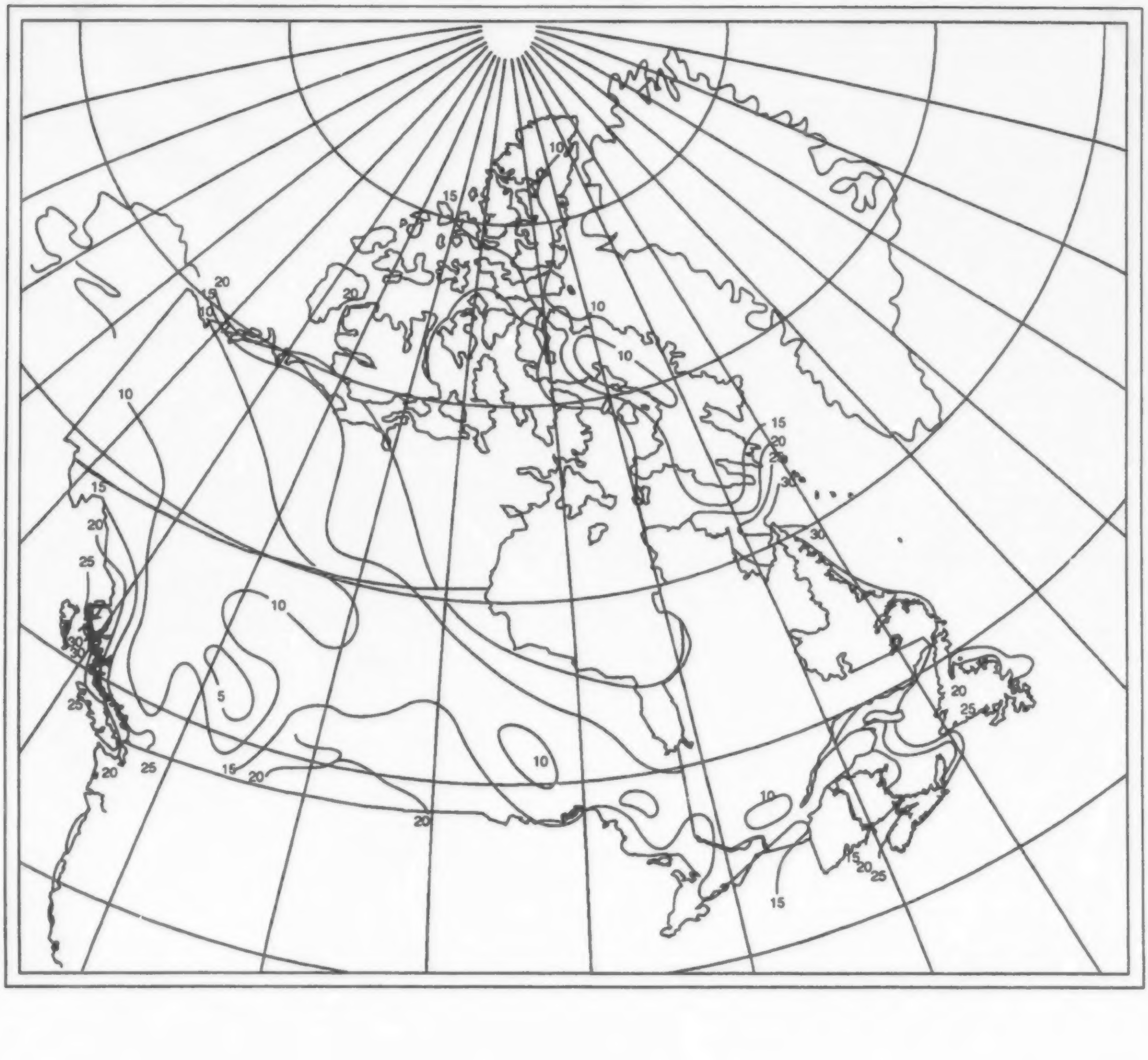
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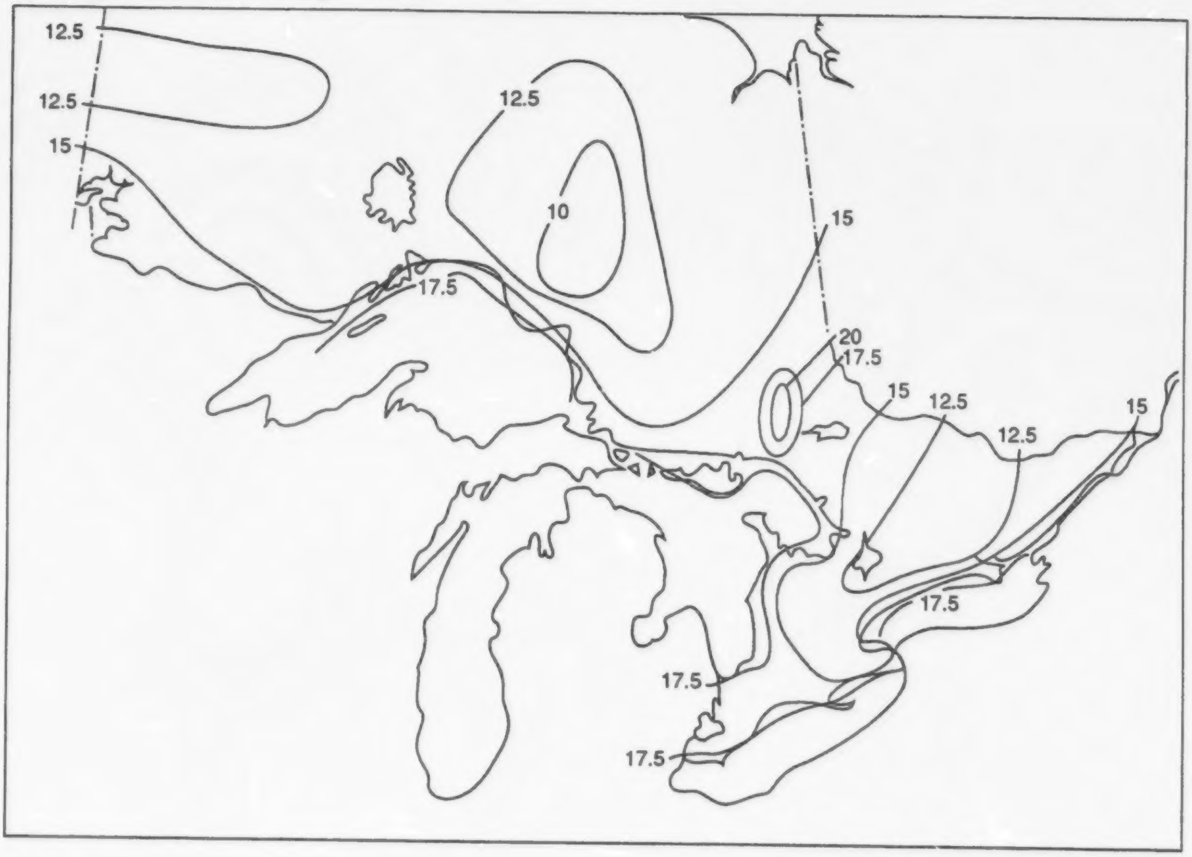
*Figure 2-2-2: Mean Wind Speed Map of Southern Ontario (Wind Speeds in km/h) [Courtesy, Environment Canada]*



.8 Figure 2-2-3 shows average hourly winter and summer wind speeds measured by Ontario Hydro at Fort Severn, which is located on the shores of Hudson Bay.

.9 Figure 2-2-4 shows average hourly winter and summer wind speeds measured by Ontario Hydro at the Kortright Centre for Conservation, near Toronto.

.10 Figure 2-2-5 illustrates seasonal wind variations and the corresponding theoretical seasonal output of a 300 kW wind turbine at Pelee Island, Lake Erie.

.11 At that location the maximum energy production would occur in December and it would be approximately double that produced in July or August.

## 2-3 Technology Description

.1 WECS convert the wind's kinetic energy into electrical energy.

.2 The wind turbine uses aerodynamic forces, lift and drag, to rotate a shaft which is usually connected through a gearbox to the electric generator.

.3 There are basically two WECS designs, horizontal axis wind turbines that have aircraft type blades, and vertical axis wind turbines that resemble inverted egg beaters with two, three or four blades.

.4 Figures 2-3-1 and 2-3-2 illustrate vertical axis and horizontal axis WECS.

*Figure 2-2-3: Average Hourly Wind Speeds at Fort Severn*

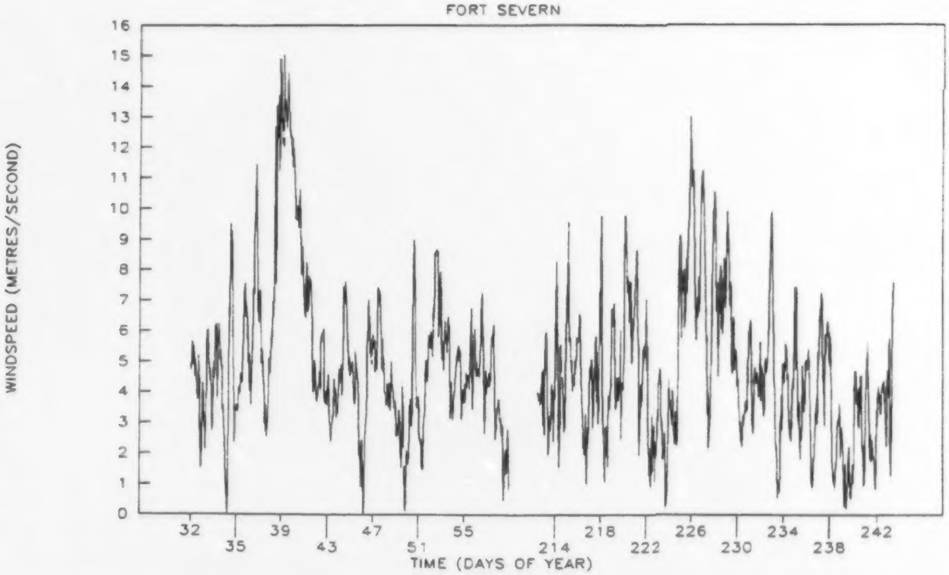


*Figure 2-2-4: Average Hourly Wind Speeds at Kortright Centre for Conservation*

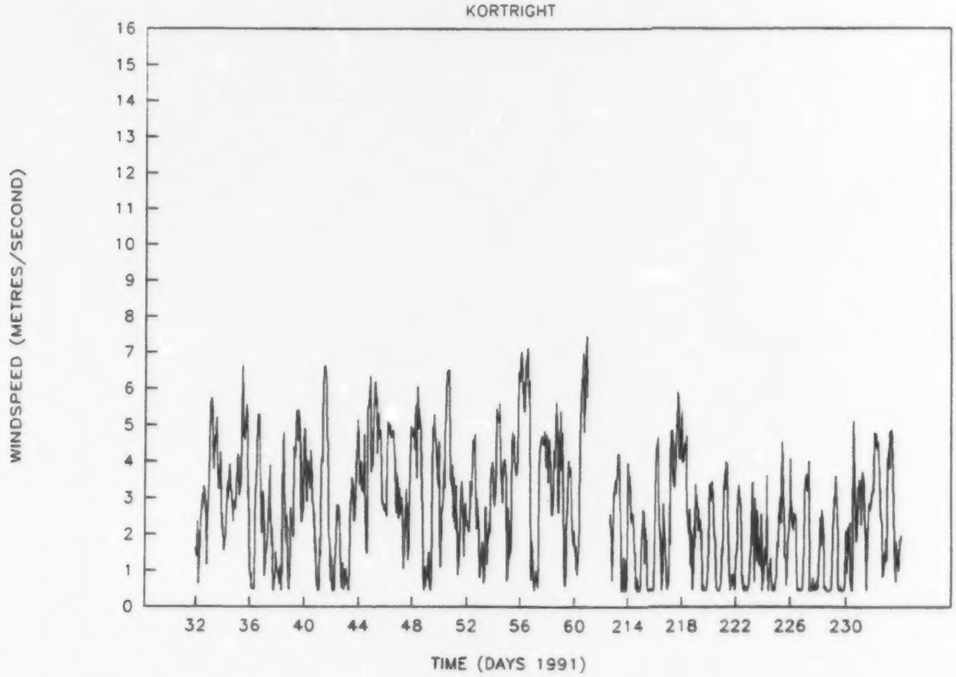
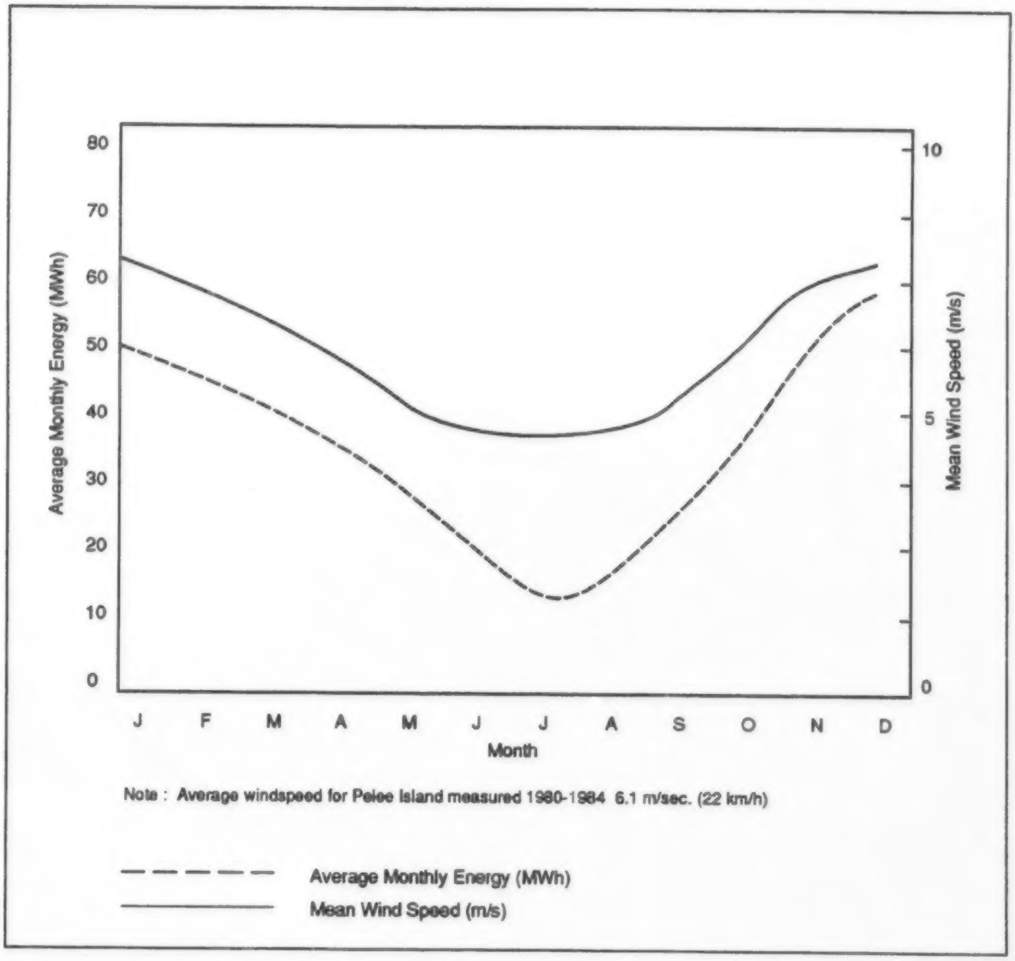
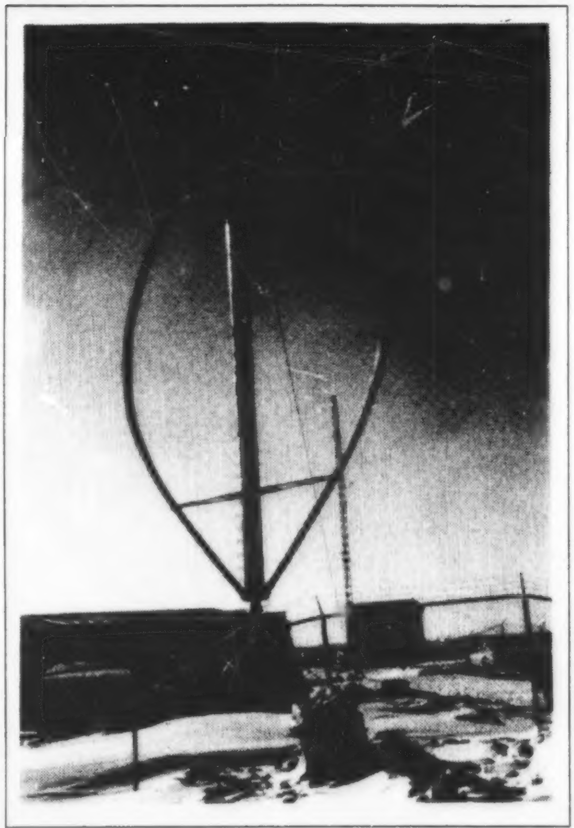


*Figure 2-2-5: Average Monthly Energy Production (Theoretical) from a 300 kW Wind Turbine on Pelee Island*



Note : Average windspeed for Pelee Island measured 1980-1984 6.1 m/sec. (22 km/h)

*Figure 2-3-1: Vertical Axis Wind Turbine, near Sudbury*



.5 Present designs are predominantly of the horizontal axis type.

.6 There are many variations of the basic horizontal axis wind turbine, including:

- upwind or downwind (relative to tower) rotors,
- the use or absence of tails, and,
- the number of blades (usually two or three blades).

.7 There is little difference between vertical and horizontal turbines in their efficiency of conversion of wind energy to electricity.

.8 Energy production from wind turbines is extremely sensitive to wind speed. Output varies as the cube of the wind speed.

.9 For example, a wind turbine exposed to average winds of 4.7 m/sec (17 km/h) would produce almost 50 percent more electricity than the same turbine exposed to winds averaging 4.2 m/sec (15 km/h).

.10 Because of daily and seasonal variations in wind speed, the energy produced also varies greatly from day to day and season to season.

.11 Some machines are designed for two-speed or variable speed operation in order to optimize energy production at various wind speeds.

.12 Blade design is an important factor in determining WECS efficiency, the challenge being to design a light blade which is robust enough to withstand the stresses experienced during the operating life of a wind turbine.

.13 Although the maximum theoretical conversion efficiency of a WECS, (known as the Betz limit) is 59.3 percent, most practical wind turbines operate with efficiencies of about 40 percent.

.14 The nominal capacity or power rating of a wind turbine is proportional to the area swept out by the turbine blades. A nominal 300 kW unit has, for example, a rotor diameter of about 33 m and sweeps an area of 855 $m^2$.

.15 Depending upon the size and design of the wind turbine, power production may be limited to periods in which the winds blow above approximately 4.4 m/sec (16 km/h) and below 20 m/sec (72 km/h).

.16 Wind speeds below about 4.4 m/sec (16 km/h) contain insufficient energy to generate electricity effectively.

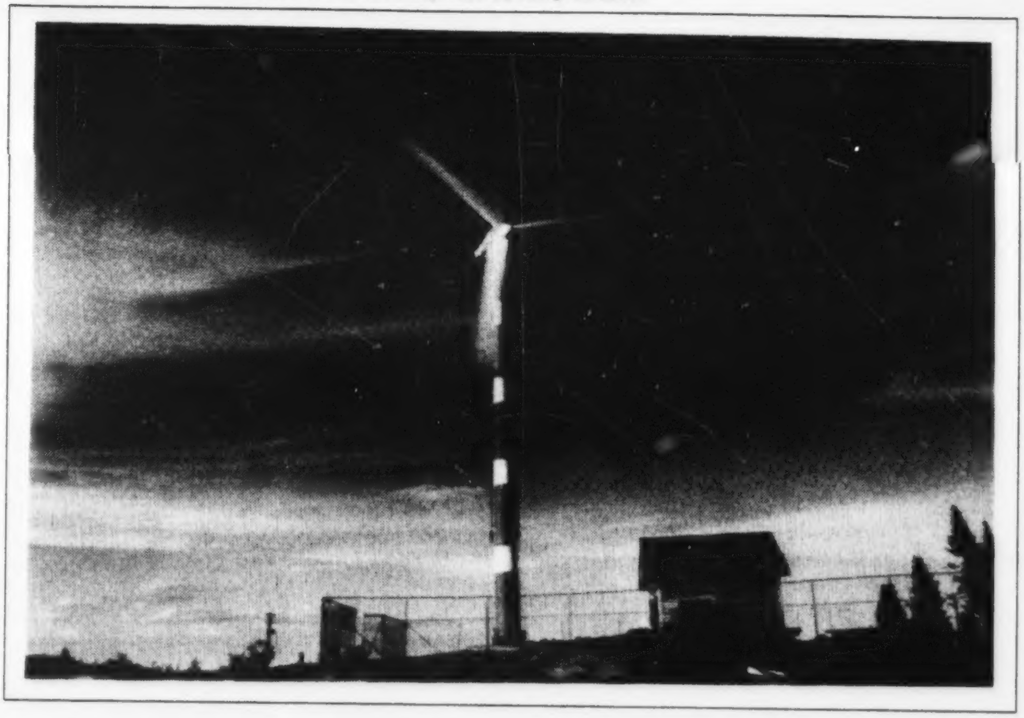
.17 Because wind speeds above approximately 20 m/sec (72 km/h) may be strong enough to damage WECS, units are designed to either brake to a stop or to tip away from the wind at higher speeds. In most locations wind speeds higher than 20 m/sec are of short duration only.

.18 Since WECS are modular, discrete units can be added together to create "wind farms". They may be arranged in a linear formation along a ridge, or spaced in a cluster with separations of about eight blade diameters to avoid interference.

.19 WECS range in nominal capacity from about 50 watts (for battery charging applications) to about 300 kW to 600 kW (for use in utility applications).

.20 WECS less than 25 kW are utilised primarily for rural residential purposes and are referred to in this report as small wind turbines.

*Figure 2-3-2: Horizontal Axis Wind Turbine, Fort Severn, Ontario*



.21 WECS connected directly to distribution systems are referred to as utility interactive generators.

.22 WECS connected to electrical grids have ranged in size from 1 kW to 4000 kW.

.23 Utility interactive WECS must meet utility requirements relating to safety and power quality.

.24 Since wind speeds vary minute by minute the power from a single WECS is characterized by extreme fluctuations – an effect which diminishes with multiple unit WECS systems.

.25 Those fluctuations can be absorbed by large electrical grids; but, unless special controls are installed the fluctuations may cause voltage on connected distribution lines to waver on smaller distribution systems.

.26 Similarly, control strategies for large WECS are designed to minimize voltage dips as the machines start up and are linked to the grid.

.27 Utility interactive WECS may incorporate either synchronous or induction generators, the latter being the more prevalent, simple and reliable.

.28 WECS with synchronous generators are designed to provide their own frequency and voltage regulation for controlled start up and synchronization with the electrical grid.

.29 Induction generators rely on the grid system itself to maintain the frequency of the generator.

.30 To date, most turbines have been designed to operate at constant speed of rotation.

.31 Variable speed turbines are now being developed and tested as they offer potential advantages including reduced power fluctuation with changes in wind speed, improved quality of supply to the grid, improved energy capture, and reduced mechanical stress of WECS components.

.32 Variable speed turbines rely on electronic power converters to produce constant frequency 60-Hz line output.

## 2-4 Experience

### 2-4-1 World Experience

.1 Mechanical WECS date back over 2000 years to early Persian windmills.

.2 Up to the time of the Industrial Revolution wind was second only to wood as a source of energy.

.3 By the late 1800s there were over six million wind-powered water pumps in North America.

.4 Development of wind-powered electrical generators, largely for charging batteries, started in the early 1900s and by the mid-1920s there were hundreds of thousands of small generators such as the Jacobs Wind Charger on farms in North America.

.5 Most small farm generators were displaced by rural electrification in the 1930s and 1940s.

.6 During the 1930s and 1940s attention turned to the design of large machines with power ratings up to 1,500 kW.

.7 As a result, large prototypes of 200 to 800 kW were tested in the UK, France and Germany with emphasis on utility applications.

.8 A 1,250 kW wind turbine was installed at Grandpa's Knob, Vermont during the 1940s.

.9 These demonstrations had problems with rotor failures due to the lack, at that time, of suitable designs capable of withstanding the mechanical stresses imposed by the wind.

.10 The comparatively lower cost of conventional power generation discouraged further development of wind turbine technology until increasing oil prices in the early 1970s renewed an interest in wind energy, particularly for electrical utility applications.

.11 In 1990 there was approximately 2,000 MW of wind energy capacity installed at locations around the world.

.12 Wind turbine manufacturers are now located in many countries including Austria, Belgium, Britain, Canada, China, Denmark, Germany, Italy, Japan, the Netherlands and the U.S.

.13 World capacity is, however, predominantly centred in two locations, California and Denmark.

.14 In 1990 California had approximately 14,000 turbines (total capacity – 1,350 MW) which generated 1 percent of that state's electrical energy. (AWEA, 1990)

.15 In 1990 Denmark had approximately 2,400 machines with a total capacity of 200 MW generating almost 2 percent of that country's electrical energy. (AWEA, 1990)

.16 To date Denmark has been the leading producer of wind turbines and has supplied many of the machines used in California.

.17 In California private developers have, over the past 10 years, installed very large wind farms comprising hundreds of machines in three mountain passes where strong winds occur.

.18 Figure 2-4-1 illustrates a California wind farm.

.19 In Denmark WECS are distributed throughout the coastal areas as individual units or in small groups of up to 20 machines. Many were installed by co-operatives.

.20 The Danes have recently begun to investigate off-shore locations. Construction of an eleven turbine facility is underway in the Baltic Sea several kilometres from Lolland Island.

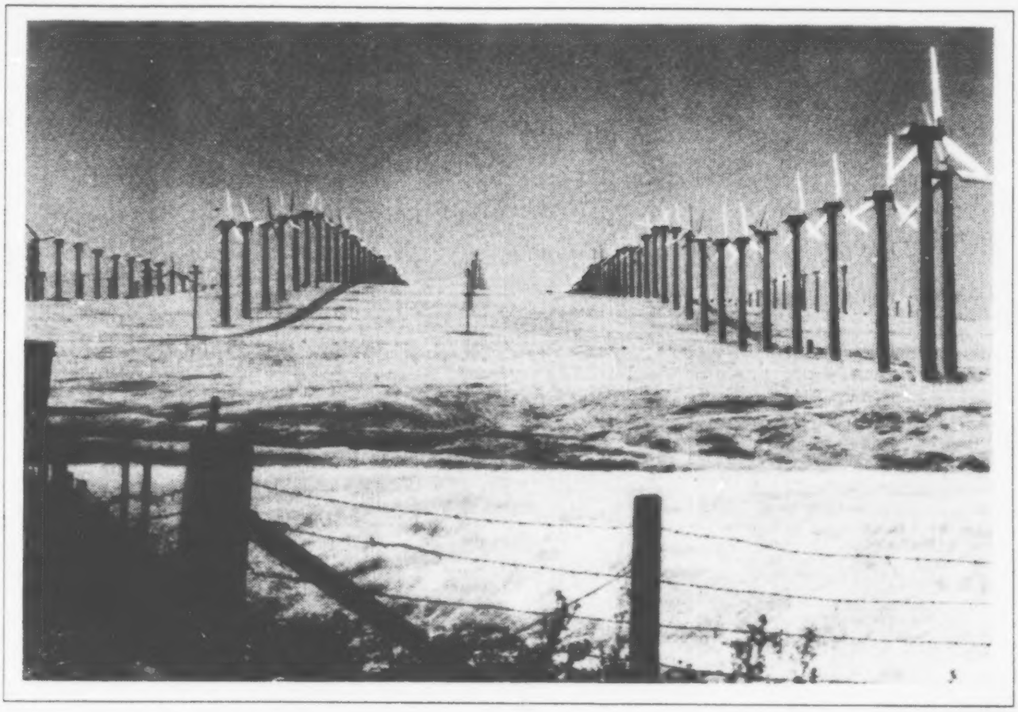
.21 The Public Utility Regulatory Policies Act of 1978 (PURPA) obliged American utilities to deal with technical and policy issues relating to parallel operation of dispersed, non-dispatchable, non-utility owned generating sources and led to standardized contracts for wind energy developers.

.22 Special tax credits and regulations also helped to promote the development of large scale wind power facilities in California in the early 1980s.

.23 The tax credits were discontinued in 1986. Construction of WECS slowed at that time, but has recently picked up again.

.24 Small individually owned residential wind turbines represent a very small proportion of installed wind capacity.

***Figure 2-4-1: A California Wind Farm***



.25 In 1989 total U.S. production of small wind turbines was about 360 units with a total generating capacity of 890 kW. (Bergey, 1990)

.26 Since the early 1980s, more than $2.5 billion has been invested in wind energy in California. By 1989 the technology produced more than 2 billion kWh annually, roughly equivalent to the annual energy demand of a city the size of San Francisco. (AWEA, 1990)

.27 As the California wind industry matured over the past decade, the efficiency of the machines improved and the availability factor of the better machines reached 95 percent. As a consequence energy production has steadily increased.

.28 Capacity factors in California have improved from an average of 13 percent in 1985 to almost 25 percent for new turbines in 1989. (EPRI, 1989)

.29 Increased reliability has resulted in decreased operations and maintenance (O&M) costs. Costs are now reported to range from U.S. 0.8 to 1.3 ¢/kWh. (EPRI, 1989)

.30 An EPRI survey of wind turbines at various sites in California and Hawaii found the following:

- Structural components (e.g., turbine blades, drive trains and yaw systems) may exhibit fatigue earlier than expected.
- Soiling of blades can lead to efficiency losses of as much as 20 percent. Very recently, rotor blade designs have been developed that are less sensitive to surface roughness.
- Productivity gains of up to 15 percent can be achieved by tailoring parameters such as the spacing between units, the blade pitch, wind speed cut-in and cut-out and time delay settings, to the specific wind conditions at each site.
- Electronic systems failed more frequently than expected due to moisture, temperature cycling, vibration and lightning strikes.

.31 The cost of wind generated electricity in California is reported to have declined from about U.S. 25 ¢/kWh in 1981 to as low as U.S. 5 ¢/kWh in 1990 at the best sites. Typical costs range from U.S. 7 to 9 ¢/kWh.

.32 While California accounts for about 80 percent of the world's wind electric generation, development is shifting to Europe.

.33 Very large wind turbines such as the 2.5 MW Mod 2 machines built by Boeing were decommissioned in the mid-1980s after their test programs. The large machines were found to be prone to stress failures and hence were not cost-effective.

.34 The largest turbines operating, at present, are listed in Figure 2-4-2.

*Figure 2-4-2: Large Wind Turbine Installations*

| Size | Manufacturer | Location |
|---|---|---|
| 4.0 MW | Shawinigan-Lavalin Inc. (derated to 2.4 MW) | Quebec, Canada |
| 3.2 MW | Boeing | Hawaii, U.S.A. |
| 3.0 MW | United Technologies | Maglarp, Sweden |
| 3.0 MW | Wind Energy Group | Orkney, U.K. |

## 2-4-2 Canadian Experience

.1 There is approximately 7.5 MW of wind turbine capacity installed in Canada. (EMR, 1991)

.2 The National Research Council of Canada has been the driving force behind research and development of wind energy technology.

.3 Although the horizontal axis wind turbine is by far the most common, Canadian R&D has strongly supported the vertical axis design.

.4 The larger installations of WECS in Canada are listed in Figure 2-4-3.

.5 Three of these installations are at North Cape, P.E.I., the site of the Atlantic Wind Test Site, Inc. facility which has been operated since 1990 under an agreement with the federal Ministry of Energy, Mines and Resources.

.6 Ontario Hydro has awarded a contract to the Atlantic Wind Test Site to evaluate various operating and control strategies for hybrid wind/diesel power plants.

.7 The facilities at the Atlantic Wind Test Site include:

- vertical axis machines of 7.5, 35, and 500 kW,
- 1 kW and 40 kW horizontal axis machines, and,
- a wind-diesel test bed incorporating two 50 kW diesels.

.8 These machines are being run on an experimental basis; however the energy generated is sold to the provincial utility.

.9 The Alberta government under the Southwest Renewable Energy Initiative Program plans to install a 9 MW wind farm in Pincher Creek beginning in 1991.

.10 That development will comprise about 30 horizontal axis WECS units manufactured by U.S. Windpower and sited along a ridge.

.11 The Pincher Creek wind farm is expected to provide an estimated 33 million kilowatt-hours per year to the Alberta energy grid. (M.E. Jones)

.12 A second wind farm is planned for the Pincher Creek Area. This facility will consist of ten 150 kW vertical axis wind turbines built by Adecon, an Ontario based manufacturer.

.13 There are also eight privately-owned and grid-connected 65 kW Nordtank wind turbines operating on farms in Alberta.

*Figure 2-4-3: Large Canadian Wind Turbine Installations*

| Owner/Operator | Site | Output | Manufacturer | Comments |
|---|---|---|---|---|
| Double A Fertilizer | Lethbridge, Alberta | 25 KW | Carter | Mechanical failure, repaired in 1988 |
| Eastridge School | Cardston, Alberta | 2 x 60 KW | Enertech | Power limited |
| B. Hargrave | Walsh, Alberta | 25 KW | Enertech | Mechanical problems, now restored |
| R. Leth | Taber, Alberta | 65 KW | Nordtank | Good performance |
| Pioneer Lodge | Ft. MacLeod, Alberta | 65 KW | Nordtank | Excellent performance |
| E. Sinnott | Pincher Creek, Alberta | 40 KW | Enertech | First utility connected unit — recently damaged in severe storm |
| NCPC | Cambridge Bay, NWT | 4 x 25 KW | Carter | Very remote environment |
| Ontario Hydro | Fort Severn, Ontario | 60 KW | Howden | Experimental, remote |
| Adecon | Orangeville, Ontario | 150 KW | Adecon | Experimental |
| Hydro Quebec | Kuujjuaq, Quebec | 65 KW | Bonus | Large diesel grid |
| Lavalin Tech Inc | Cap-Chat, Quebec | 4 MW | Vickers | Experimental, limited output |
| AWTS | Prince Edward Island | 500 KW | Indal | Energy production |
| AWTS | Prince Edward Island | 40 KW | Enertech | Energy production |
| AWTS | Prince Edward Island | 35 KW | Indal | Hybrid diesel experimental |
| NLPC | Bell Island | 250 KW | Carter | Recent installation |

An agreement between U.S. Windpower and the Alberta government to install a 9 MWe windfarm near Pincher Creek was recently announced

### 2-4-3 Ontario/Ontario Hydro Experience

.1 A few very small wind turbines, some owner built, have operated in Ontario in remote locations since the 1970s, largely for charging batteries.

.2 The emphasis in Ontario has been on the development of hybrid wind/diesel systems to operate on small, isolated diesel-powered grids serving remote northern communities.

.3 In 1982 Ontario Hydro was involved with other parties in the development and installation of a hybrid wind/diesel power plant at a test site near Sudbury. The wind turbine was rated at 35 kW and had a 20 metre diameter aluminum blade rotor. Two diesel generators of 50 kW each operated in parallel with the wind turbine.

.4 The purpose of the Sudbury tests was to evaluate the hybrid operation of a wind turbine with diesel power plants.

.5 That 35 kW vertical axis machine and the two 50 kW diesel generators are the units now undergoing further tests at the Atlantic Wind Test Site in Prince Edward Island (discussed above).

.6 Figure 2-3-1 shows the machine when it was installed at the Sudbury test site.

.7 Since 1987 Ontario Hydro has operated a prototype hybrid wind/diesel system at Fort Severn, the province's most northerly community.

.8 That system, illustrated in Figure 2-3-2, consists of a 60 kW horizontal axis wind turbine operated in parallel with 85 kW of diesel generation.

.9 In 1988 approximately 7 percent of the community's annual electricity requirements were met by the wind turbine even though winds in the area averaged only 5 m/sec (18 km/h).

.10 Figure 2-4-4 summarizes the performance of the Fort Severn wind turbine for a one year period from June 1989 to May 1990.

.11 Currently, one of the two wind turbines connected to Ontario Hydro's main grid is a 3.5 kW machine operating at Science North in Sudbury. This machine is used for demonstration purposes and serves to reduce the science centre's electricity purchases. Performance results are unavailable.

.12 In the summer of 1991, staff of Ontario Hydro and the Kortright Centre for Conservation installed a 10 kW wind turbine to provide a public demonstration of the technology and the requirements for utility connection. The Kortright unit replaces a smaller WECS installed at the same location in the early 1980s to charge batteries.

## 2-5 Potential System Application

.1 Wind turbines should be located in areas where wind speeds are adequate to generate power economically.

.2 Aesthetic considerations will also limit the areas in which wind turbines can be deployed.

.3 Modularity would enable: (1) the addition of small blocks of capacity to match growth in demand, and (2) dispersal of the units to reduce transmission costs (within the siting limits discussed above).

.4 The potential ways in which wind power plants can serve utilities include smaller units in remote communities, privately owned and operated installations where the unit basically serves the needs of the owner with any excess power being sold to the utility grid, and wind farms, comprised of several turbines each of a few hundred kilowatts capacity, which serve the grid.

.5 Incorporating wind energy options into a small remote community requires careful engineering design and consideration of maintenance requirements.

.6 As the wind is an intermittent source of energy, energy from a wind turbine is not available on demand. Remote systems must therefore be used in conjunction with backup electricity generation or storage systems.

.7 In California, good sites have demonstrated annual capacity factors of 20 to 30 percent and since utility demand frequently coincides with wind power supply, the machines can be given some capacity credit. The annual capacity factor in Ontario would be lower, in the 15 to 20 percent range.

.8 Wind energy systems are non-dispatchable. As discussed in Part 1, Section 1-7, issues surrounding the impact on electricity systems of the use of many non-dispatchable sources of electricity must be studied and resolved before wind energy options can achieve high penetration levels.

.9 Although WECS up to 4 MW have been built, the industry is standardizing on units in the 300 to 600 kW range for utility wind farm applications. Units much smaller than 300 kW are not efficient for commercial developers. Units larger than 600 kW result in technical problems of scaling, complexity and stress on components.

## 2-6 Environmental Considerations

.1 This section of the review discusses environmental considerations, both natural and social, associated with wind turbines.

.2 While there are environmental concerns and potential safety hazards associated with the production of wind turbines, the management of environmental effects associated with pre-fabrication are assumed to be included in the price of the items, and are not addressed in detail.

### 2-6-1 Natural Environment

.1 This section discusses environmental and safety issues associated with wind turbines under the headings of air, land, water and other.

*Air*

.2 Interest in wind turbines for utility application arises largely because of their negligible emissions to the environment and their use of a renewable energy source.

*Figure 2-4-4: Performance Statistics of Fort Severn Wind Turbine*

| Month | Average windspeed (m/sec) | Wind turbine output (kWh) (measured) | (estimated) | Community demand (kWh) (measured) | Percent wind energy | Comments* |
|---|---|---|---|---|---|---|
| June 1989 | 4.65 | 3497 | | 50695 | 6.9 | 2 days inhibit |
| July | 3.87 | 1060 | | 38649 | 2.7 | 2 days inhibit 5 days missing data |
| August | 4.19 | 2411 | | 47479 | 5.1 | 2 days inhibit |
| September | 5.07 | 5642 | | 55251 | 10.2 | 1 1/2 days inhibit |
| October | 5.00 | 264 | 5000 | 8700 | 3.0 | 5 days inhibit 26 days missing data |
| November | 4.85 | 441 | 4000 | 8898 | 5.0 | 2 days inhibit 20 days missing data |
| December | 3.96 | 502 | 1000 | 29543 | 1.7 | 4 days inhibit 11 1/2 days missing data |
| January 1990 | 4.30 | 3715 | | 44441 | 3.9 | 5 days inhibit |
| February | 5.10 | 5874 | | 80505 | 7.3 | 100 % availability |
| March | 6.40 | 5625 | 13000 | 39484 | 14.2 | 18 days missing data |
| April | 5.40 | 8305 | | 77426 | 10.7 | 1 1/2 days inhibit |
| May | 4.60 | 3689 | | 81198 | 4.5 | 3 days inhibit |
| | Total | 41025 | 54143 | 612269 | 6.7 | |

*Inhibit indicates that the wind turbine is unavailable because of a fault trip or maintenance within the diesel plant.

Missing data results from problems with data logger.

### *Land*

.3 In many respects environmental impacts associated with WECS construction are expected to be similar to those resulting from transmission tower construction, although WECS are more likely to be clustered.

.4 Construction activities could involve excavation for concrete footings and the use of heavy equipment. Impacts could include soil compaction and erosion.

.5 Typical wind farm installations involve the use of underground cable and dispersed ground-level transformers to deliver energy to the grid.

.6 Terrestrial impacts would be influenced by existing land use patterns. For example, if a forest has to be clearcut, terrestrial impacts will be different than in a situation utilizing existing agricultural land. Typically only about 5 percent of the land is occupied by the wind turbine, roads and associated equipment. Land under a wind farm could continue to be used for some agricultural pursuits, such as grazing. (Swisher, 1991)

.7 Dismantling of wind turbines would involve impacts similar to those associated with the dismantling of transmission towers. (ERDA, 1977)

.8 Decommissioned WECS contain many parts which can be recycled; the remaining components present no unusual or hazardous disposal problems.

### *Water*

.9 There are no aquatic emissions associated with the operation of WECS.

.10 Construction activities associated with wind turbines may require precautions to minimize erosion and siltation of local water bodies.

.11 Precautions may be required to minimize disturbance to aquatic habitats if WECS are constructed along shorelines.

*Other*

.12 The potential exists for birds to collide with towers, rotors, and transmission lines, particularly along migratory routes. (ERDA, 1977)

.13 Although some wind turbine blades can interfere with television reception (ERDA, 1977), the use of non-metallic materials in the blades effectively eliminates this concern.

.14 WECS turbine blades could fail and could be thrown hundreds of metres; however, regular inspections and maintenance reduce this hazard.

### 2-6-2 Social Environment

.1 This section discusses issues associated with wind turbines and their impact on the social environment under the headings of socio-economic effects and societal considerations.

*Socio-Economic Effects*

.2 There is presently a small industrial infrastructure for the manufacture of wind energy conversion systems (WECS) in Canada. With socio-economic incentives the manufacture, installation and servicing of WECS may stimulate limited regional economic development.

.3 Local community impacts would likely be limited to noise and visual impact. Concerns would be localized and mitigated with appropriate siting and design.

.4 Social impacts related to construction of wind farms are not expected to be different from impacts associated with the construction of transmission lines.

*Societal Considerations*

.5 Wind is a renewable energy source. In addition, WECS produce minimal residual or harmful waste products.

.6 Environmentally attractive features of wind based electricity generation have resulted in a significant degree of social acceptance of this energy option.

.7 As Ontario's windiest sites are located along the Hudson Bay coastline and along the westward facing shores of the Great Lakes, aesthetic impacts related to the location of wind farms may be important in some locales.

## 2-7 Operational Considerations

.1 Large wind turbines require expert maintenance of both the electronic and mechanical systems.

.2 While maintenance costs are reported to be about 0.8 to 1.3 U.S. ¢/kWh for reliable wind turbines on California wind farms, costs are likely to be higher in Ontario's northern regions because of the remoteness of the sites. The high cost of maintenance may be slightly offset by lower maintenance requirements at sites such as Fort Severn where turbulence and therefore stress on the machines may be lower.

.3 Some wind farms in California assign a maintenance crew (mechanical, electrical and electronic technician) for every 20 to 25 machines.

## 2-8 Development Issues

*Small Wind Turbines*

.1 For small wind turbines, 25 kW or less, no major breakthroughs in efficiency are expected. The best units are already achieving rotor/alternator efficiencies of about 40 percent, compared to the theoretical limit of 59.3 percent.

.2 For small wind turbines the greatest potential breakthrough lies in cost reductions resulting from high volume production. Reductions of 20 to 35 percent may be possible with annual production of 1,000 residential units (10 MW total). (Bergey, 1990)

*Large Wind Turbines*

.3 Large wind turbine technology has matured over the past five years. Recent units, in California and Denmark, are reported to have achieved availability factors greater than 95 percent.

.4 Steady, incremental advances in turbine design and power and control electronics, together with economies of scale associated with mass production may lead to a 20 to 30 percent reduction in the cost of wind energy over the next 10 to 15 years.

.5 Areas of current turbine development include reduced sensitivity of turbine blades to soiling, turbines capable of operating at variable speed and improved fatigue resistance.

.6 A major challenge is to improve the cost effectiveness of wind turbines, particularly for use in regions of moderate wind speeds.

## 2-9 Selected Options

### 2-9-1 Option 1: 10 kW Single Wind Turbine

.1 This wind power system would consist of a single wind turbine connected to the service entrance of the owner/operator via a line commutated inverter. A typical installation is illustrated in Figure 2-9-1.

.2 Typically the installation would be sited at a farm or rural residence and be owner-operated. The machine would have a 7 metre rotor diameter and a tower height of 30 metres for efficient wind capture. Property requirement would be about 0.5 hectares.

.3 Why select a 10 kW turbine? The 10 kW wind turbine would, on an annual basis, closely match the electrical energy demand of a typical rural residential owner.

.4 Why not select a smaller or larger wind turbine? Since utility interconnection requirements are largely independent of size for this range of generators, very small wind turbines would not produce enough electricity to make the connection worthwhile. Larger machines, up to 60 kW, have been used in Alberta farm installations where the larger output is met by a matching larger demand. However, larger machines with their added complexity require special maintenance by trained personnel.

.5 Why owner-operated? The 10 kW wind turbine is a relatively simple machine to operate. The unit can readily be maintained by the owner/operator.

### 2-9-2 Option 2: Wind farm (20 units rated at 350 kW each)

.1 This wind farm consists of twenty 350 kW wind turbines connected to the utility distribution system via a dedicated transformer station. The wind turbines would have a rotor diameter of approximately 30 metres and individual machines would be separated by eight or more blade diameters. A typical installation is shown in Figure 2-9-2.

.2 Siting in areas of high average wind speed is critical to energy production. Good locations in Southern Ontario would be the Pelee Island area of Lake Erie or the Bruce area of Lake Huron, and some areas around Sudbury.

.3 Why select 350 kW machines? This is representative of the optimum size (about 300 to 600 kW) evolving in the industry. Units much less than 300 kW are not efficient for commercial developers. Units larger than 600 kW involve technical problems of scaling, complexity and stress on components.

.4 Why select 20 units? Wind energy is dispersed and is therefore suited for distributed generation – except for one requirement. Wind turbines require maintenance. Experience shows that a single maintenance crew (mechanical, electrical and electronic technician) can serve 20 to 25 machines. This, therefore, is considered minimal for commercial operation. Because Ontario does not have specific sites with very high wind speeds, Ontario is not likely to follow California's pattern of very large wind farms. The Danish pattern of small groupings of wind turbines is more likely.

## 2-10 Costs and Performance

.1 This section discusses the costs and performance assumptions used to assess the 10 kW and 20 x 350 kW wind energy options. The measure used to assess the wind energy options is the cost/benefit ratio previously discussed in Part 1, Section 1-7.

.2 For the purposes of this assessment, the two options are assumed to be located in Sudbury, Ontario.

*Figure 2-9-1: Small Utility Interactive Wind Turbine*

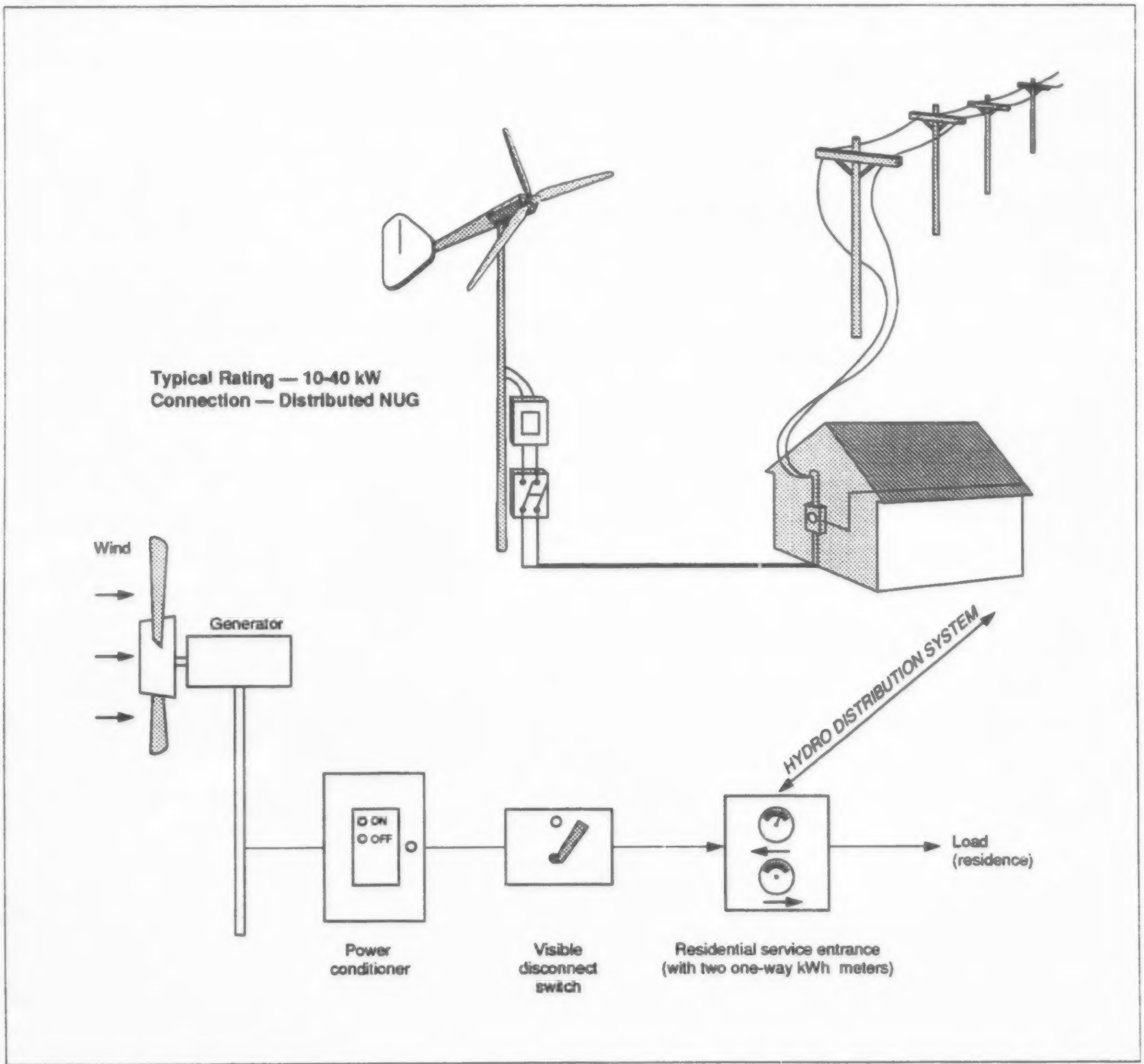
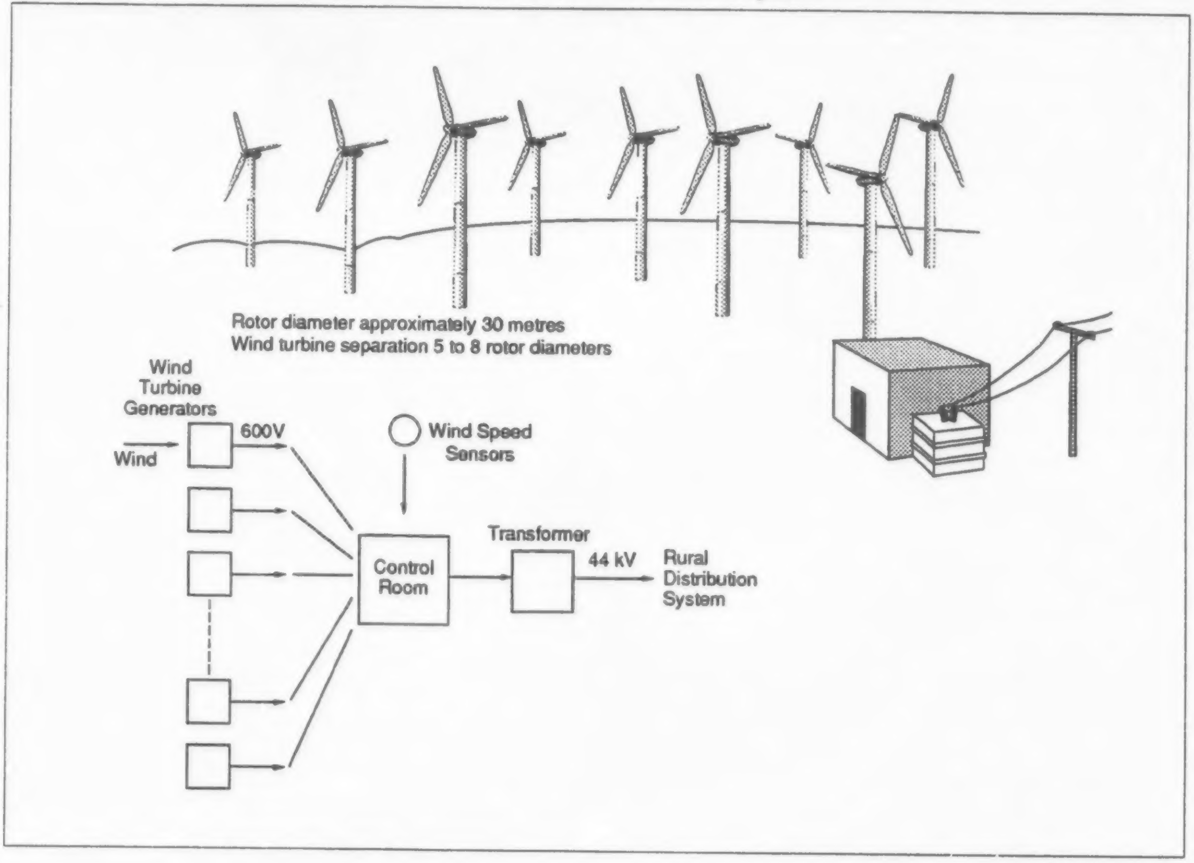

Typical Rating — 10-40 kW
Connection — Distributed NUG
Wind
Generator
HYDRO DISTRIBUTION SYSTEM
ON
OFF
Load
(residence)
Power conditioner
Visible disconnect switch
Residential service entrance
(with two one-way kWh meters)

*Figure 2-9-2: Schematic of a Wind Farm Connected to a Rural Distribution System*


Rotor diameter approximately 30 metres
Wind turbine separation 5 to 8 rotor diameters
Wind Turbine Generators
Wind
600V
Wind Speed Sensors
Control Room
Transformer
44 kV
Rural Distribution System

### 2-10-1 Performance Assumptions

.1 Figure 2-10-1 below summarizes the performance assumptions used in evaluating the wind energy options.

.2 The useful life of 25 years is a judgement, and is not based on experience.

.3 The annual capacity factor of 22 percent is based on Ontario Hydro experience and wind speed data for Sudbury, Ontario.

### 2-10-2 Calculation of Benefits: Wind Energy Systems

.1 The benefits of wind energy installations to an electricity system are two-fold – the value of the energy produced by the installation and the value of the "capacity" provided by that installation to the system. This latter benefit, known as the "capacity credit", is discussed in Part 1, Section 1-7 of this review. Wind energy options are also eligible for the 10 percent "renewables" credit discussed in the same section.

.2 In addition, both of the wind energy options assessed here are eligible for credits for avoiding transmission and distribution costs and losses. These credits are discussed below.

*Value of Energy Produced*

.3 Estimates of the total annual energy and the daily and seasonal variation in the energy production are also required to calculate the benefits of the energy produced by a wind energy installation to an electricity system or owner/operator.

.4 There are four categories of energy known as summer peak energy, winter peak energy, summer off-peak energy and winter off-peak energy, each of which has a different value to an electricity system.

*Figure 2-10-1: Wind Energy Performance Assumptions*

| Option | Description | Useful Life (yrs.) | Annual Capacity Factor (%) | Annual Energy Production (MWh) |
|---|---|---|---|---|
| 1 | 10 kW | 25 | 22 | 18.9 |
| 2 | 7 MW | 25 | 22 | 13,230 |

.5 Environment Canada wind speed data for Sudbury were used to calculate the energy which would be produced by each wind energy option during each hour of the day and during each month of the year. This energy production was then split into the four categories of energy discussed above. The value of this energy was then calculated, using Ontario Hydro incremental system values of energy.

.6 The estimated energy production from each of the two options, split into the four categories indicated, as well as the present value (PV) of this energy, in 1991 dollars, are shown in Figure 2-10-2.

*Figure 2-10-2: Value of Energy Produced – Wind Energy Installations*

|  | Option 1: 10 kW | Option 2: 7 MW |
|---|---|---|
| Winter Peak Energy (MWh) | 5.4 | 3,767 |
| Winter Off-Peak Energy (MWh) | 5.8 | 4,072 |
| Summer Peak Energy (MWh) | 4.2 | 2,955 |
| Summer Off-Peak Energy (MWh) | 3.5 | 2,436 |
| Total Energy Produced (MWh) | 18.9 | 13,230 |
| Present Value of Energy (000s $ 1991) | 5.276 | 3,624.2 |

.7 Note that, as would be expected, the largest proportion of the energy produced by a wind energy installation occurs during the winter when the average wind speeds are highest.

### *Capacity Credit*

.8 Wind energy installations are considered to be eligible for a partial capacity credit since there is a correlation between the time when the wind is most likely to be blowing and the time when system peak demand is likely to occur. This benefit is estimated at 30 percent of the nominal rating based on the likelihood of energy production from wind energy installations being available at the time when system peak demand occurs.

.9 The present value of the capacity credit for Option 1 (10 kW) is estimated to be $2,560.

.10 The present value of the capacity credit for Option 2 (7 MW) is estimated to be $1,397,100.

### *Renewables Credit*

.11 Wind energy installations would be eligible for a "renewables credit" of 10 percent of the sum of the benefits (energy and capacity) produced by the option.

.12 For Option 1 (10 kW), this credit is 10 percent of the total of the capacity and energy benefits calculated above – that is, $784.

.13 For Option 2 (7 MW) this credit is $502,100.

### *Transmission and Distribution Credits*

.14 Included in the above present values of capacity and energy are credits for avoiding bulk electricity system costs ($12/kW/yr), regional supply system costs ($7/kW/yr), distribution system costs ($10/kW/yr) and a credit for avoiding transmission and distribution losses (7 percent of the total value of energy and capacity).

.15 Option 1 (10 kW) received all of the credits listed above; however, Option 2 (7 MW) because it would likely be connected at the regional supply level (because of its larger size), does not receive the distribution system credit ($10/kW/yr) and receives a 5 percent distribution loss credit instead of 7 percent.

### *Summary of Benefits*

.16 The present value of the benefits for the two wind energy options are summarized below in Figure 2-10-3.

*Figure 2-10-3: Summary of Benefits – Wind Energy Installations (000s $ 1991)*

| | Option 1: 10 kW | Option 2: 7 MW |
|---|---|---|
| Energy Benefit | 5.276 | 3,624.2 |
| Capacity Credit | 2.560 | 1,397.1 |
| Renewables Credit | 0.784 | 502.1 |
| Total Benefits | 8.620 | 5,523.4 |

### 2-10-3 Cost Estimates

.1 As discussed in Part 1, Section 1-7, the cost estimates for wind energy installations are based mainly on surveys of manufacturers and on industry surveys regarding costs and cost trends. Ontario Hydro's experience with wind energy installations is limited to demonstration projects.

.2 Cost estimates are based on the most current information available to Ontario Hydro. The costs are intended to provide an indication of a range of costs and not definitive estimates of the cost of options.

.3 The cost estimates for the wind energy options are presented as both current costs and projected costs in the year 2000.

.4 As the fuel for this option is the wind there are no fuelling costs.

.5 Capital and OM&A cost estimates for the wind energy options are shown in Figure 2-10-4. As is true of all wind energy installations the capital cost of the equipment is the overriding cost factor.

*Present Value of Costs*

.6 The present values of the costs of the two wind energy options are summarized in Figure 2-10-5.

### 2-10-4 Net Present Value and Cost/Benefit Ratio Summary

.1 The present value of the benefits, the present value of the costs as well as the net present values and cost/benefit ratios for the wind energy options are summarized in Figure 2-10-6.

.2 The results show that, for the two options analyzed, the cost/benefit ratio is estimated to be greater than one (negative net present values) for both options, for both 1991 costs and projected year 2000 costs.

*Figure 2-10-4: Cost Estimates – Wind Energy Options*

| Cost Component | Option 1 – 10 kW | | Option 2 – 7 MW | |
|---|---|---|---|---|
| | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs |
| Initial Capital ($/kw) | 2,600 | 2,200 | 1,740 | 1,490 |
| Later Capital ($/kW/yr) | 0 | 0 | 16 | 16 |
| OM&A (¢/kWh) | 0.7 | 0.7 | 1.4 | 1.4 |

*Figure 2-10-5: Present Value of Costs – Wind Energy Options (000s $ 1991)*

| Cost Component | Option 1 – 10 kW | | Option 2 – 7 MW | |
|---|---|---|---|---|
| | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs |
| Total Capital | 13.8 | 11.7 | 7,367.7 | 6,443.7 |
| OM&A | 1.2 | 1.2 | 1,709.2 | 1,709.2 |
| Total | 15.0 | 12.9 | 9,076.9 | 8,152.9 |

*Figure 2-10-6: Summary of Costs and Benefits – Wind Energy Options*

| | Option 1 – 10 kW | | Option 2 – 7 MW | |
|---|---|---|---|---|
| | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs |
| PV of Costs (000s $ 1991) | 15.0 | 12.9 | 9,076.9 | 8,152.9 |
| PV of Benefits (000s $ 1991) | 8.6 | 8.6 | 5,523.4 | 5,523.4 |
| Net PV (000s $ 1991) | -6.4 | -4.3 | -3,553.5 | -2,629.5 |
| Cost/Benefit Ratio | 1.7 | 1.5 | 1.6 | 1.5 |
| LUEC (¢/kWh)* | 10.6 | 9.1 | 9.1 | 8.2 |

* LUEC is provided for information only and should be interpreted with care. As discussed in Part 1, Section 1-7, LUEC is not the appropriate measure with which to assess wind energy systems.

## 2-10-5 Sensitivities

.1 For each option, the sensitivities of the net present value and the cost/benefit ratio to variations in the values of the individual cost components, in economic factors and in performance, are presented. Sensitivity analyses provide indications of the variability of the net present value and the cost/benefit ratio to changes in cost and performance assumptions.

.2 The cost estimates for wind energy installations are subject to large uncertainties, particularly when considering projected year 2000 costs. These large uncertainties are reflected in the uncertainty ranges.

.3 The sensitivity ranges are not intended to reflect a particular confidence level. The level of information available does not lend itself to such detailed analysis. They simply represent Ontario Hydro's judgement on the possible variation of these factors.

.4 Figures 2-10-7 and 2-10-8 show the sensitivity ranges for costs and performance respectively, and the effect of those ranges on the net present value and cost/benefit ratios for the two options assessed.

.5 Given the assumptions in this report regarding costs and performance, the largest range of net present values and cost/benefit ratios for each option can obtained by assuming that all cost components and performance factors are fully dependent. That is, if one cost component increases, all cost components are assumed to increase and all performance factors are assumed to decrease, and vice-versa. In this manner, an indication of the upper and lower ranges of the net present values and cost/benefit ratios for each option are obtained. These upper and lower estimates are shown in Figure 2-10-9.

*Figure 2-10-9: Overall Sensitivity – Wind Energy Options (All Factors Dependent)*

| | Overall Sensitivity – Cost/Benefit Ratios | | |
|---|---|---|---|
| | Lower Estimate | Point Estimate | Upper Estimate |
| **Option 1:** | | | |
| 1991 Costs | 1.1 | 1.7 | 4.0 |
| 2000 Costs | 1.1 | 1.5 | 3.7 |
| **Option 2:** | | | |
| 1991 Costs | 1.1 | 1.6 | 3.3 |
| 2000 Costs | 1.1 | 1.5 | 3.2 |

*Figure 2-10-7: Cost Component Sensitivities – Wind Energy Options*

| | Point Estimate | | Range Assumed (%) | | Sensitivity (%) * | |
|---|---|---|---|---|---|---|
| | Cost | Present Value (000s $) | Lower | Upper | Lower | Upper |
| **Option 1: 1991 Costs** | | | | | | |
| Capital | 2600 $/kW | 13.8 | -20 | +20 | -18.4 | +18.4 |
| OM&A | 0.7 ¢/kWh | 1.2 | -10 | +15 | -0.8 | +1.2 |
| Total | N/A | 15.0 | N/A | N/A | -19.2(1) | +19.6(1) |
| **Option 1: 2000 Costs** | | | | | | |
| Capital | 2200 $/kW | 11.7 | -10 | +30 | -9.1 | +27.2 |
| OM&A | 0.7 ¢/kWh | 1.2 | -10 | +15 | -0.9 | +1.4 |
| Total | N/A | 12.9 | N/A | N/A | -10.0(1) | +28.6(1) |
| **Option 2: 1991 Costs** | | | | | | |
| Capital | 2140 $/kW | 7,367.7 | -20 | +20 | -16.2 | +16.2 |
| OM&A | 1.4 ¢/kWh | 1,709.2 | -20 | +15 | -1.9 | +2.8 |
| Total | | 9,076.9 | N/A | N/A | -18.1(1) | +19.0(1) |
| **Option 2: 2000 Costs** | | | | | | |
| Capital | 1890 $/kW | 6,443.7 | -10 | +20 | -7.9 | +23.7 |
| OM&A | 1.4 ¢/kWh | 1,709.2 | -10 | +15 | -2.1 | +3.1 |
| Total | N/A | 8,152.9 | N/A | N/A | -10.0(1) | +26.8(1) |

* Percentage change in total present value of costs for each option.

(1) Total sensitivities are calculated as if all cost components are fully dependent.

*Figure 2-10-8: Performance Sensitivities – Wind Energy Options*

| Factor | Point Estimate | Present Value (000s $) | Range Assumed | | Sensitivity (%) * | |
|---|---|---|---|---|---|---|
| | | | Lower | Upper | Lower | Upper |
| **Option 1:** | | | | | | |
| Annual Capacity Factor | 22% | 5.3 | 25% | 19% | 9.4 | -9.4 |
| Capacity Credit (% of rating) | 30% | 2.6 | 40% | 0% | 10.9 | -32.7 |
| Life (years) | 25 | N/A | 30 | 20 | 8.8 | -11.0 |
| Renewables Credit | 10% | 0.8 | 10% | 10% | 0.0 | 0.0 |
| Total Benefit | | 8.6 | | | | |
| **Option 2:** | | | | | | |
| Annual Capacity Factor | 22% | 3,624.2 | 25% | 19% | 10.0 | -10.0 |
| Capacity Credit (% of rating) | 30% | 1,397.1 | 40% | 0% | 9.3 | -27.8 |
| Life (years) | 25 | N/A | 30 | 20 | 8.8 | -11.0 |
| Renewables Credit | 10% | 502.1 | 10% | 10% | 0.0 | 0.0 |
| Total Benefit | | 5,523.5 | | | | |

* Percentage change in total present value of benefits for each option.

### 2-10-6 Cost Summary

.1 This assessment of wind energy installations indicates that they are not currently economic sources of generation for the bulk electricity system in Ontario.

.2 This conclusion is based on cost/benefit ratios of greater than one (negative net present values) for the two wind energy options assessed. That is, capital and operating costs would not be recovered over the life of the options.

.3 When costs are projected to the year 2000 the results show that, although there is some improvement, the cost/benefit ratio remains at greater than one for both options. However the lower estimates (low costs, high performance) indicate cost/benefit ratios approaching one.

## 2-11 Potential

### 2-11-1 Scenario Descriptions

.1 The potential for wind energy systems is assessed under the three scenarios described earlier in Part 1, Section 1-8. These scenario descriptions are repeated below:

*Scenario 1:* In this scenario, it is assumed that there is no improvement in current costs and technological status by the year 2000. The potential contribution by the year 2005 is assessed.

*Scenario 2:* In this scenario, an attempt is made to account for cost and technological improvements which may occur by the year 2000. Given these improvements, the potential contribution by the year 2005 is reassessed.

*Scenario 3:* The projections in this highly speculative scenario are based on assumptions that significant improvements in technology and costs could occur by the year 2010. The potential contribution by the year 2014 is assessed.

### 2-11-2 Projections of Potential

.1 Figure 2-11-1 shows the forecast of potential contribution for wind energy systems under the three scenarios described above.

.2 Under Scenario 1 there is limited potential for wind energy systems in Ontario by the year 2005. Based on current technology and costs, as well as site specific nature of the resource, only niche applications are expected by the year 2005.

.3 Under Scenario 2 there is also limited potential for wind energy systems in Ontario by the year 2005. Even assuming improvements in technology and costs projected for the year 2000. As in Scenario 1, the site specific nature of the resource, as well as the limited period for implementation of year 2000 technology results in a projection of less than 1 MW.

.4 Under Scenario 3, the potential for wind energy systems for utility connected systems is estimated to be up to 40 MW in Ontario. The estimate is based on forecasts made in a report to Energy Mines and Resources, Canada. (EMR, 1991)

*Figure 2-11-1: Forecast of Potential Contribution of Wind Energy Systems*

| Scenario | Assumptions | Major Factors Affecting Potential | Cost Compared to Conventional Generation | Potential | | Potential Applications |
|---|---|---|---|---|---|---|
| | | | | MW | By Year | |
| 1 | • Current cost<br>• Current technology | • Survey for potential locations<br>• Capital cost | Above | < 1 | 2005 | • Niche<br>• Individual units |
| 2 | • Incremental improvement in technology<br>• Little change in costs | • As above | Above | < 1 | 2005 | • As above |
| 3 | • Reduction in capital costs to ≤$1,100/kW. | | Equal to or lower | 10 – 40 | 2014 | • Wind farms and individual units |

## 2-12 Overall Assessment

.1 Interest in wind turbines results from their negligible pollutant emissions and their use of a renewable energy source.

.2 Wind power is a proven technology. Wind power has advanced greatly over the past decade with most development occurring in California and Denmark. Most recent windfarms demonstrate over 95 percent availability for individual machines.

.3 Cost estimates in this review indicate that wind power is not currently economic for the production of electricity for the bulk electricity system in Ontario.

.4 In Ontario, wind power would likely be first applied in niche applications involving off-grid hybrid systems (e.g., wind/diesel), where the cost of the displaced generation is high. Ontario Hydro currently operates a hybrid wind/diesel demonstration project at a remote community.

.5 On-grid application of wind power would likely be in the form of dispersed non-utility generation (i.e., single wind turbines or wind farms).

.6 Energy output from wind turbines is very site dependent; therefore, in-depth investigation of potential wind sites is required for optimum siting.

.7 Wind farms require large tracts of land; however, much of that land is available for other uses such as agriculture.

.8 The potential for wind power in Ontario is limited by the availability of sites having suitable wind speeds. As discussed in Section 2-11 the potential contribution of wind power to the electricity supply mix for Ontario could be as little as 1 MW by the year 2000 or as high as 40 MW by the year 2014 depending on costs and technological developments.

.9 The advantages of wind energy include:

- use of a renewable energy source,
- no fuel costs,
- no pollutant emissions,
- minimal waste products,
- modularity, and
- generally high levels of social acceptance in other jurisdictions.

.10 Barriers to large scale wind development include:

- limited number of good wind sites in Ontario,
- intermittent availability of power, and
- the amount of land potentially required for large wind farms.

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# Part 2: Technology Assessments

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## 3-1 Introduction

.1 Fuel cells convert the chemical energy of a fuel directly into electricity by means of an electrochemical process, rather than via a thermal combustion process with an intermediate steam cycle.

.2 The concept of the fuel cell is 150 years old but it only started to see serious development with the space program in the late 1950s and early 1960s.

.3 All fuel cells currently being developed rely ultimately on hydrogen, or a hydrogen/carbon monoxide mixture, as the principal fuel and oxygen as the oxidant.

.4 Like a battery, a fuel cell consists of an anode, a cathode and an electrolyte.

.5 Unlike batteries which must be replaced or recharged, fuel cells can supply power as long as fuel and oxidant are supplied from external sources.

.6 The fuel is supplied to the anode and the oxidant is supplied to the cathode.

.7 Fuel cells are classified by the type of electrolyte used.

.8 The five principal fuel cell types that have been or are currently being developed are illustrated in Figure 3-1-1:

- Alkaline Fuel Cell (AFC)
- Solid Polymer Fuel Cell (SPFC), also known as the Proton Exchange Membrane Fuel Cell (PEMFC)
- Phosphoric Acid Fuel Cell (PAFC)
- Molten Carbonate Fuel Cell (MCFC)
- Solid Oxide Fuel Cell (SOFC)

.9 Figure 3-1-2 illustrates schematically the operation of a simple acid-electrolyte fuel cell.

.10 Hydrogen flows over the anode and dissociates into positively-charged hydrogen ions and negatively-charged electrons.

.11 The electrons flow through the external circuit to the load, while the hydrogen ions move through the anode into the electrolyte.

.12 Electrons return from the external circuit to the cathode which is supplied with oxygen.

.13 Finally, the hydrogen ions, electrons and oxygen combine inside the cell producing water and heat.

.14 The electrolyte facilitates the electrochemical process by allowing the hydrogen ions to move between the electrodes, thereby completing the electrical circuit.

.15 As discussed above, hydrogen ions act as the ionic charge carrier in acid electrolyte fuel cells, such as the SPFC and the PAFC, and carry charge from the anode to the cathode.

.16 In the MCFC, AFC and SOFC, the charge carriers are, respectively, the carbonate ion, the hydroxyl ion, and the oxygen ion, which, in each case, carry charge from the cathode to the anode.

.17 Figure 3-1-3 shows an exploded view of a typical fuel cell.

.18 A practical fuel cell power plant consists of at least three basic components – fuel processor, a fuel cell power section, and a power conditioner as shown in Figure 3-1-4. Those fuel cell plants which operate at higher temperatures, may incorporate a heat recovery system to utilize available byproduct heat.

*Figure 3-1-1: Fuel Cell Types Defined by Electrolyte*

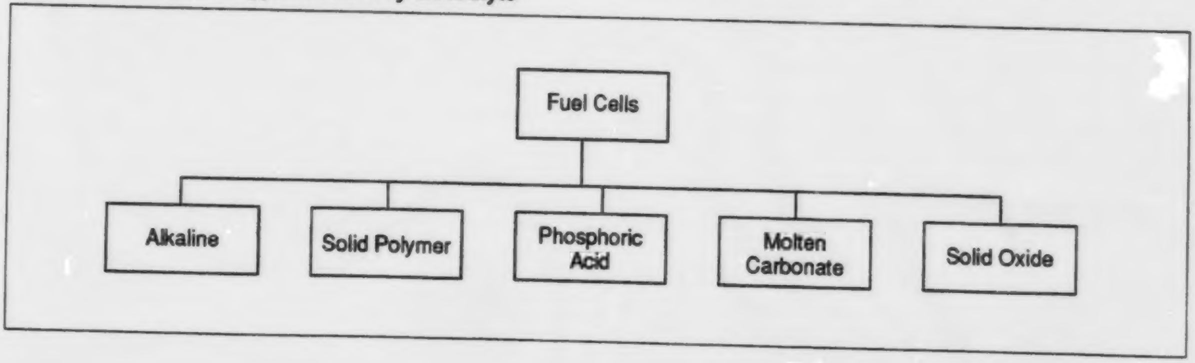
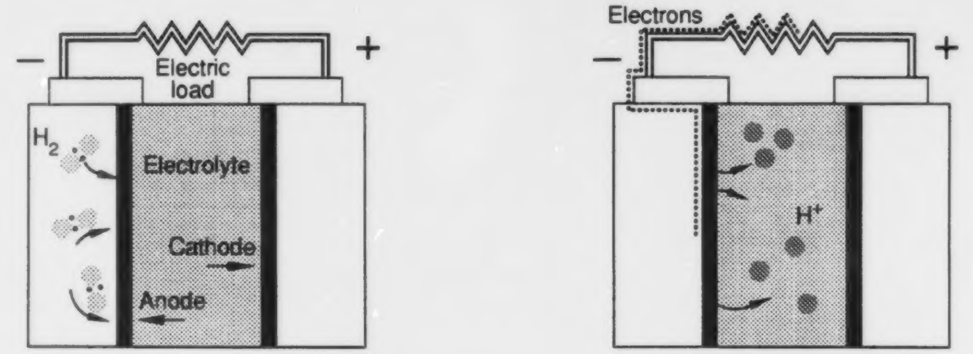
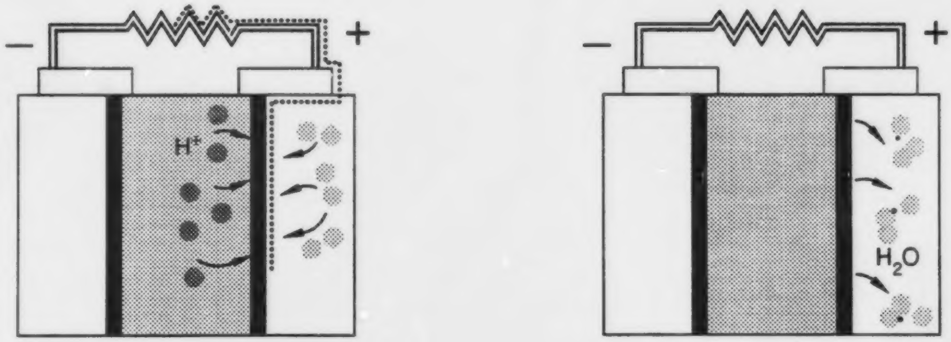


*Figure 3-1-2: Schematic Representation of the Operation of a Simple Acid-Electrolyte Fuel Cell [Source: U.S. Congress O.T.A., 1985]*



1. Hydrogen gas flows over the anode.

2. Electrons split away from hydrogen and flow through anode to external electric load.



3. Hydrogen ions move through electrolyte to cathode. Electrons stream into cathode from load. Cathode is bathed with oxygen.

4. Hydrogen, electrons, and oxygen combine to form water (steam).

.19 The fuel processor converts a commercially available fuel such as natural gas into hydrogen-rich gas of the type required for use in the fuel cell power section.

.20 The fuel cell power section consists of one or more stacks of individual fuel cells which produce direct current electricity.

.21 Figure 3-1-5 shows three sizes of phosphoric acid fuel cell stacks.

.22 The power conditioner is typically an inverter which converts the direct current output from the fuel cell power section to alternating current (a.c.). The power conditioner can also regulate voltage and current.

*Figure 3-1-3: Schematic of a Three-Cell Fuel Stack (Exploded View of Centre Cell) [EPRI, 1986]*

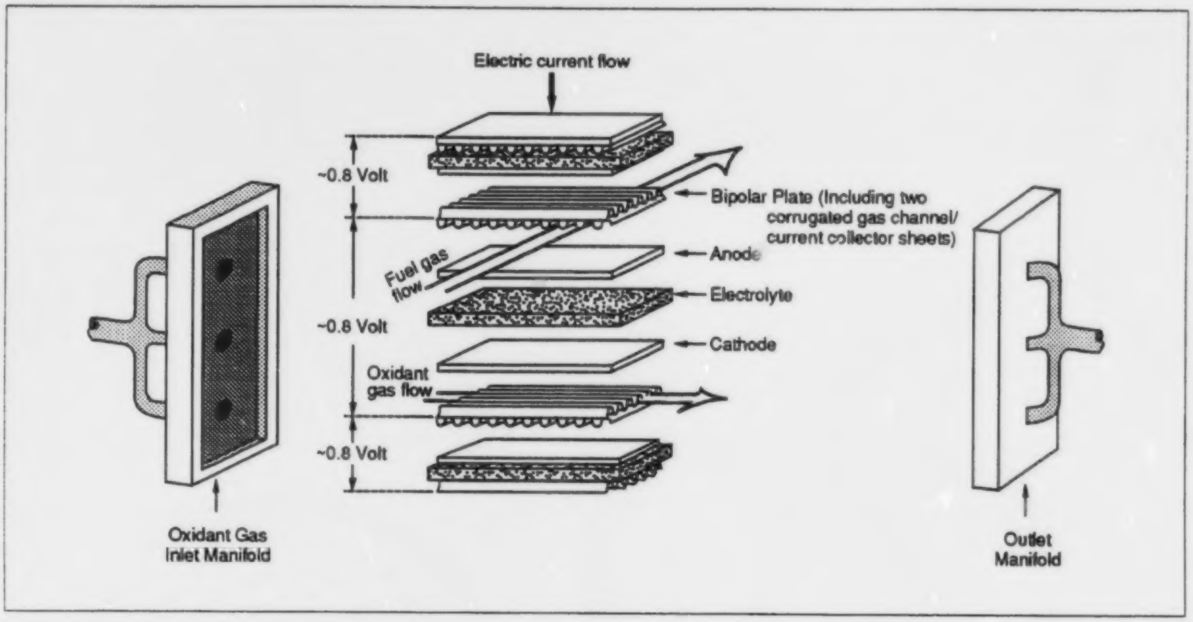

Electric current flow
~0.8 Volt
Bipolar Plate (Including two corrugated gas channel/ current collector sheets)
Fuel gas flow
Anode
Electrolyte
~0.8 Volt
Cathode
Oxidant gas flow
~0.8 Volt
Oxidant Gas Inlet Manifold
Outlet Manifold

*Figure 3-1-4: Generalized Schematic of a Fuel Cell Power Plant*

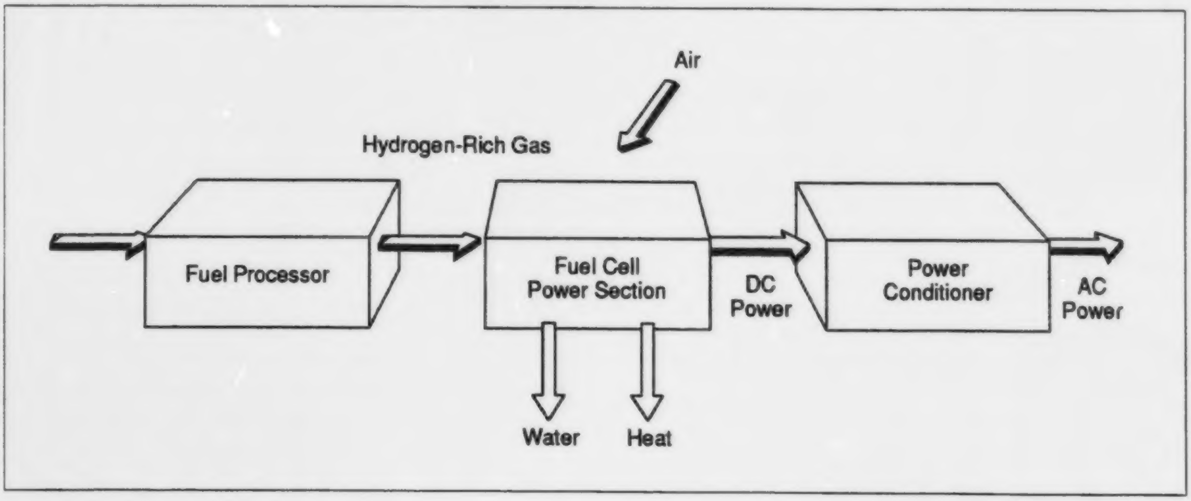
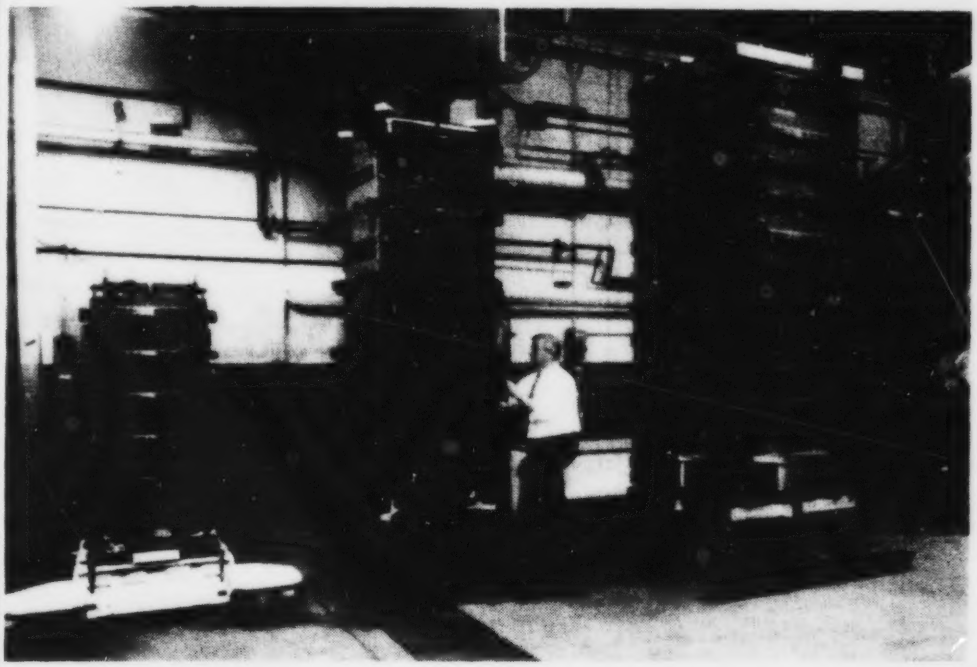

Air
Hydrogen-Rich Gas
Fuel Processor
Fuel Cell Power Section
DC Power
Power Conditioner
AC Power
Water
Heat

*Figure 3-1-5: Phosphoric Acid Fuel Cell Stacks [Courtesy of International Fuel Cells]*



40 kW 200 kW 700 kW

## 3-2 Fuel/Energy Resources

### 3-2-1 Introduction

.1 As previously stated, all fuel cells require a fuel (ideally pure hydrogen) and an oxidant (ideally pure oxygen). Some fuel cells, notably the SOFC and MCFC, can use a hydrogen/carbon monoxide ($H_2/CO$) mixture as fuel, thereby facilitating direct use with reformed natural gas or methanol, as well as synthesis gas derived from coal.

### 3-2-2 Oxidant

.1 Oxygen is usually obtained from the air unless the specific application can justify the cost of pure oxygen or an oxygen separation system.

.2 A small loss in performance occurs when air is used instead of pure oxygen, but this is usually acceptable because of the energy consumption, extra cost, weight and complexity of oxygen storage or enrichment systems.

.3 Hydrogen peroxide is another potential, but expensive, source of oxygen. It is used only for specific niche applications in which performance and not cost is the determining factor.

### 3-2-3 Fuel

.1 Pure hydrogen is expensive and difficult to handle and store.

.2 As in the case of pure oxygen, pure hydrogen is used only for specific niche applications where the cost and complexity of handling this fuel can be justified.

.3 Most commercial fuel cell power plants include a fuel processing or reforming component, as shown previously in Figure 3-1-4, to produce hydrogen-rich gas from readily available fuels, such as natural gas.

.4 Processing the fuel at the point of use produces hydrogen-rich gas at the rate required by the fuel cell power section and reduces the need for costly and difficult storage of hydrogen.

.5 The two high temperature fuel cells (MCFC and SOFC) can accommodate internal reforming. This process increases efficiency and reduces cost since a separate reformer is not required.

.6 Four sources of hydrogen, or $H_2$/CO mixtures, which have been shown to be potentially economic are:

- light hydrocarbon gases such as methane (natural gas) and propane,
- light hydrocarbon liquids such as naphtha and methanol,
- heavier hydrocarbon liquids such as No. 2 and No. 6 fuel oil, and
- coal.

.7 Hydrocarbon fuels are generally cheaper and easier to handle, but are much less reactive than hydrogen. There are three methods of converting light hydrocarbon fuels to hydrogen:

- steam reforming (inside or outside the fuel cell),
- partial oxidation, and
- pyrolysis.

.8 Steam reforming involves the reaction of light hydrocarbon fuels (gas or liquid) with steam to produce hydrogen and carbon dioxide.

.9 Autothermal reforming, a variation of steam reforming, is a process which involves the reaction of hydrocarbon fuels with air as well as steam. This process can accommodate somewhat heavier hydrocarbons and has been demonstrated to operate satisfactorily with No. 2 fuel oil. (Appleby & Foulkes, 1989)

.10 Partial oxidation is a process in which light hydrocarbon fuel is incompletely burned (oxidized) to produce hydrogen and carbon monoxide.

.11 Partial oxidation may be the only practical method available to obtain hydrogen from heavy hydrocarbon fuels with high sulphur contents, such as No. 6 fuel oil. (Appleby & Foulkes, 1989; EPRI, 1985)

.12 Pyrolysis is a process in which light hydrocarbons are heated to high temperatures in the absence of air until they are broken down or "cracked" into hydrogen and carbon.

.13 A coal gasification system can be used to obtain hydrogen from coal. This process produces syngas (a mixture of hydrogen and carbon monoxide) when coal reacts with oxygen and steam in a gasifier at high temperatures. Coal gasification is optimized by use of oxygen rather than air. This process is economic only where used in large facilities. (EPRI, 1986)

.14 Hydrogen can also be derived from other sources such as ammonia and hydrazine.

.15 The energy required to produce hydrazine greatly exceeds the energy that is obtained from the fuel cell and this fact, together with hydrazine's high cost and toxicity, limits its use to military applications. (Appleby & Foulkes, 1989)

.16 Ammonia may be fed directly to a fuel cell and is readily available commercially. However, ammonia fuel cells have undergone little development and are not considered suitable for economic power production, except for specialized remote, low-power systems where ammonia supplies may be readily available.

.17 Figure 3-2-1 provides a summary of hydrogen production processes.

### 3-2-4 Summary

.1 As a result of the developments in fuel processing technologies the most attractive near term option is steam reforming of light hydrocarbon fuels such as natural gas.

.2 Liquid fuels such as methanol and naphtha are attractive for use in remote applications because they are readily transportable and can be converted to hydrogen by steam reforming.

*Figure 3-2-1: Summary of Hydrogen Production Processes*

| Process | Acceptable fuels | Product gases | Comments |
|---|---|---|---|
| Direct | Pure hydrogen | Pure Hydrogen | Expensive |
| Indirect steam reforming | Light hydrocarbons - (Natural gas, propane, naphtha)<br>methanol | $H_2$<br>CO<br>$CO_2$ | External reformer required.<br>Catalyst required.<br>Sulphur removal required.<br>Commercially available and demonstrated with a fuel cell. |
| Direct steam reforming high temperature | Natural gas,<br>aqueous methanol | $H_2$, $CO_2$ | Fuel gas reformed internally with steam in the fuel cell stack.<br>Sulphur removal required.<br>Demonstrated on a small scale. |
| Autothermal reforming | No. 2 fuel oil | $H_2$, CO, $CO_2$ | Not commercially available |
| Pyrolysis | Hydrocarbon fuels | C, $H_2$, $CH_4$ | Catalysts required to reduce production of $CH_4$<br>Process can tolerate impurities.<br>Limited amount of experience and no method yet developed to integrate the process with a fuel cell power plant. |
| Partial oxidation | Light hydrocarbons, methanol, heavy hydrocarbon fuels with sulphur | $H_2$, CO, $CO_2$, $N_2$, $H_2S$ | $H_2$ production eficiency less than with steam reforming.<br>Fast startup capability and compact size are attractive features for transportation applications.<br>Only process that works with heavy fuel oil with high sulphur content.<br>Not yet demonstrated with a fuel cell. |
| Gasification | Coal | $H_2$, CO, $CO_2$, $H_2S$ | Expense and eficiency penalty of coal gasifiers require that this process be applied only to large, central fuel cell power plants.<br>Number of processes available.<br>Sulphur as $H_2S$ removed from gasifier product gases.<br>No gasifier/ fuel cell power plant yet demonstrated. |

.3 Coal gasification may become attractive in the long term for large centralized generating stations, depending on the price of natural gas.

.4 If the "Hydrogen Economy" becomes a reality, perhaps by the middle of the 21st century, pure hydrogen may be readily available for fuel cell operation.

## 3-3 Technology Description

### 3-3-1 Introduction

.1 This section of the chapter provides a more detailed description of the different fuel cell types and their performance characteristics.

.2 This section concludes with a figure comparing the advantages and disadvantages of the major fuel cell types.

.3 The rate of power production in a fuel cell is determined by a number of factors, including the following: (1) the flow rate and pressure of the fuel and oxidant gases, (2) the transfer rates of the ions in the conducting electrolyte, and (3) the surface area available for the catalytic dissociation and recombination reactions that take place on the electrodes. (Fichett and Linden, 1984)

.4 The net fuel cell reaction is that of hydrogen (or hydrogen and carbon) and oxygen producing water (and $CO_2$ in the case of CO) and electrical energy, ideally at a voltage of 1.23 Volts d.c. for a single cell.

.5 In practice, fuel cells produce useful voltage outputs that are somewhat less than the ideal (typically in the range 0.5 to 0.9 Volts d.c.), and which decrease with increasing load (current density). This voltage reduction results from energy losses associated with the reactions in the cell which are referred to as polarization losses.

.6 The performance of a fuel cell is represented by the current density versus voltage (or "polarization") curve as shown in Figure 3-3-1. There are three major polarization losses in a fuel cell – activation losses related to over-potentials at the electrode, ohmic losses related to internal resistance in the fuel cell circuit, and losses related to the flow of charge carriers through the electrolyte.

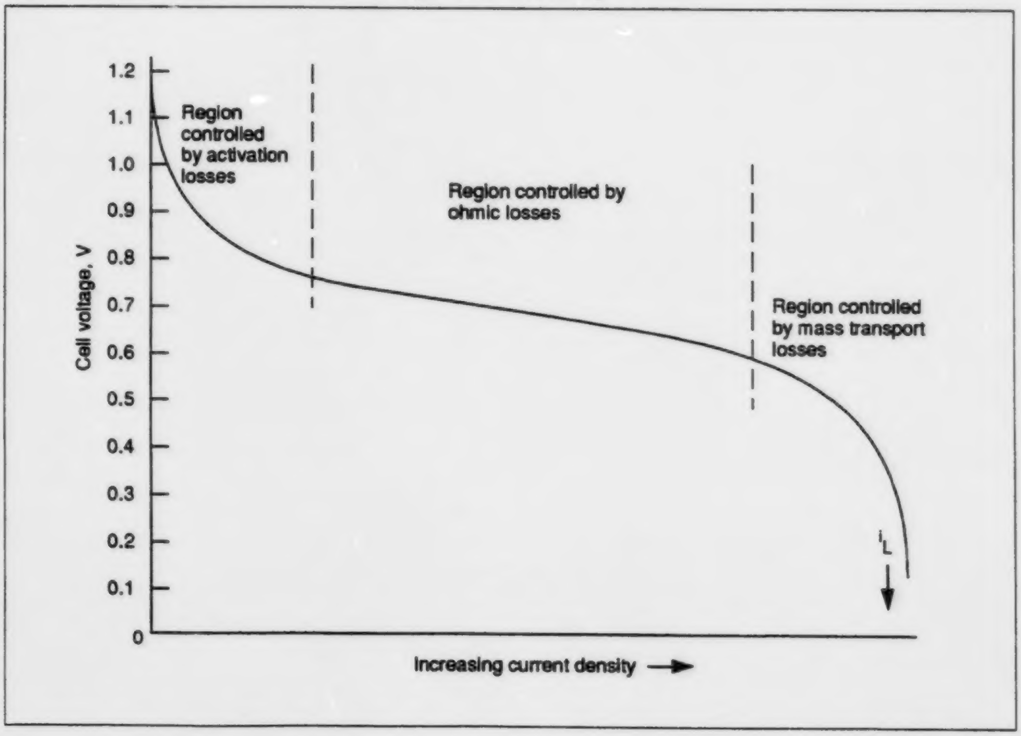
.7 As noted in Section 3-1 there are five principal types of fuel cells which have been developed or are actively under development today. These are classified by electrolyte as follows:

- Alkaline Fuel Cell (AFC)
- Solid Polymer Fuel Cell (SPFC), also known as Proton Exchange Membrane Fuel Cell (PEMFC)
- Phosphoric Acid Fuel Cell (PAFC)
- Molten Carbonate Fuel Cell (MCFC)
- Solid Oxide Fuel Cell (SOFC)

.8 Other fuel cell systems based on sulphuric acid, aqueous carbonate, and molten alkaline electrolytes have not found a niche in a practical fuel cell application. The sulphuric acid electrolyte has marginal stability, aqueous carbonate systems tend to be too low in performance for all but a very few specialty applications, and the molten alkaline system seems to have been dropped by developers due to its complexity. (Appleby & Foulkes, 1989)

.9 There are several other types such as direct methanol fuel cells, direct ammonia fuel cells, and proton-conducting fuel cells; but, they are either applicable to niche markets other than the utility market, or they require significant development and/or improvements in design and performance to make them competitive with the five main fuel cell types available today. (Kalia, 1982; Appleby & Foulkes, 1989)

*Figure 3-3-1: Fuel Cell Polarization Curve [after Fickett, 1984]*



.10 In comparing the different fuel cell types the electrolyte dictates such factors as:

- operating temperature/materials used/onstruction,
- type of fuel and required purity,
- whether the cell can be fuelled directly, and
- capability for heat recovery.

.11 Combining the above considerations results in the relatively few practical fuel cell combinations shown in Figure 3-3-2.

.12 These technologies are described in more detail in the following sections.

### 3-3-2 Alkaline Fuel Cells

.1 The most common type of alkaline fuel cell (AFC) uses an electrolyte of concentrated potassium hydroxide (KOH) solution.

.2 Because of the relatively low temperature of operation (50 to 260°C), electrocatalysts are required to assist the electrochemical reactions at the electrodes.

.3 As required by the particular application, the operating temperature and performance of the fuel cell can be increased by increasing the concentration of potassium hydroxide.

.4 AFCs are normally fuelled with pure hydrogen and pure oxygen and can attain efficiencies of 55 to 65 percent.

.5 Fuel gas streams from processed hydrocarbon fuels contain carbon monoxide (which affects the electrocatalysts) and carbon dioxide (which affects the electrolyte). Either CO and $CO_2$ removal systems or an electrolyte cleanup system must be employed if processed hydrocarbon fuels are used.

### 3-3-3 Solid Polymer (or Proton Exchange) Fuel Cells

.1 Solid polymer fuel cells (SPFCs) use an ion-exchange polymer membrane (fluorinated sulphuric acid polymer), similar in nature to Teflon, as electrolyte.

.2 Operation of SPFCs is limited to less than 120°C, as the polymer electrolyte becomes non-conducting above this temperature.

.3 The low temperature operation of SPFCs allows relatively fast start up, but requires the use of a platinum catalyst to assist the electrochemical reactions at the electrodes.

.4 SPFCs can achieve efficiencies of 55 percent when fuelled by pure hydrogen and oxygen. (Prater, 1991)

.5 SPFCs can also utilize reformed light hydrocarbon fuels such as methanol at an efficiency of about 40 percent.

.6 SPFC electrolyte systems can tolerate carbon dioxide in the fuel and oxidant streams due to the acid nature of the polymer. However, carbon monoxide must be removed from the fuel gas stream to prevent degradation of the platinum catalyst in the electrodes.

.7 The uses of expensive platinum catalyst and relatively expensive polymers are issues to be addressed if this technology is to become commercial.

.8 One of the most promising SPFC technologies is Canadian, the Ballard SPFC.

### 3-3-4 Phosphoric Acid Fuel Cells

.1 The phosphoric acid fuel cell (PAFC) is the most common type of acid electrolyte system.

.2 PAFCs operate in the temperature range from 190 to 210°C.

.3 The temperature of operation is still sufficiently low, however, that electrocatalysts such as platinum must be used in the electrodes to assist the electrochemical reactions.

.4 Waste heat can be utilized to provide steam for reforming and/or hot water for space heating.

.5 The efficiency of PAFCs fuelled by natural gas or light hydrocarbon liquid fuels is approximately 40 percent. A PAFC can be operated at either atmospheric pressure, or at pressures up to 10 atmospheres to improve output and efficiency.

*Figure 3-3-2: Classification of Practical Fuel Cells*

| Fuel Cell Type (By Electrolyte) | Operating Temperature (°C) | Nominal Efficiency (Fuel to Electricity) | Fuel/Oxidant | Fuel Processing | Status/Applications |
|---|---|---|---|---|---|
| Alkaline | 50 - 260 | 55 - 65% | $H_2/O_2$ | Direct | Well developed for niche applications such as space vehicles and submarines. |
| Solid Polymer | 80 - 120 | 55%<br>40+%<br>40% | $H_2/O_2$<br>$H_2$/Air<br>Methanol/Air | Direct<br>Direct<br>External steam reforming | Used in Gemini space capsules. Under development for transportation applications. |
| Phosphoric Acid | 190 - 210 | 49.5%<br>40%<br>40% | $H_2$/Air<br>Light Hydrocarbons/Air<br>Methanol/Air | Direct<br>External steam reforming<br>External steam reforming | Most mature fuel cell technology for land based applications. Commercialization efforts underway in both the U.S. and Japan for use in on-site cogeneration and dispersed utility applications. |
| Molten Carbonate | 650 | 54 - 60%<br>45% | Natural Gas/Air<br>Syngas/Air | Direct<br>External coal gasification | Under development for on-site cogeneration an dispersed utility applications, as well as large central power plants fuelled by coal. |
| Solid Oxide | 1000 | 50%<br>45% | Natural Gas/Air<br>Syngas/Air | Direct<br>External coal gasification | Under development for on-site cogeneration and dispersed utility applications, as well as large central power plants fuelled by coal. |

.6 Light hydrocarbons and methanol can be used as fuels since acid electrolyte systems can tolerate carbon dioxide and trace amounts of carbon monoxide in the fuel and oxidant streams.

.7 The PAFC is the most mature of the fuel cell technologies being developed for terrestrial power applications.

### 3-3-5 Molten Carbonate Fuel Cells

.1 Molten carbonate fuel cells (MCFCs) utilize an electrolyte consisting of a combination of lithium, sodium, or potassium carbonates, retained in a ceramic matrix of lithium aluminate.

.2 MCFCs operate at approximately 650°C, a temperature at which the alkali carbonates form a highly conductive molten salt.

.3 At this temperature expensive platinum catalysts are not required since the nickel anodes and nickel oxide cathodes support the electrochemical reactions.

.4 MCFC power plants fuelled by natural gas can achieve efficiencies of 54 to 60 percent, based on the lower heating value of the fuel, and depending on the fuel cell power plant design. The high operating temperature of the MCFC can be utilized to achieve higher overall plant efficiencies in combined cycle plants.

.5 MCFCs can utilize reformed light hydrocarbon fuels or coal syngas.

.6 MCFCs are unique among fuels cells in that they utilize carbon dioxide ($CO_2$) in the fuel and oxidant gas streams to replenish carbonate ions lost in the overall cell reactions.

.7 The high operating temperature of MCFCs allows direct fuel reforming of natural gas in the fuel cell by utilizing the steam and the heat produced by the cell to support the reforming reaction.

.8 The technology still requires development to address issues related to scale-up, corrosion, leaking seals, cathode dissolution, and cell life. Internal or external reforming is another issue, as are ultimate costs per kW and size of module. The minimum fuel cell module size for a combined cycle plant is likely to be about 5 MW.

.9 Despite these problems two U.S. firms and several Japanese companies are aggressively marketing this technology for commercial availability in the middle to late 1990s.

### 3-3-6 Solid Oxide Fuel Cells

.1 Solid oxide fuel cells (SOFCs) use an electrolyte that is a solid, 100 percent dense (i.e., non-porous) metal oxide, typically yttria-stabilized zirconia. Other similarly exotic ceramic materials are used in the cathodes and anodes.

.2 SOFCs operate at approximately 1000°C, a temperature at which charge transfer can take place by the conduction of oxygen ions through the electrolyte.

.3 SOFCs achieve efficiencies of about 50 percent when fuelled with natural gas. The high operating temperature of the SOFC can be utilized to achieve higher overall plant efficiencies in combined cycle plants.

.4 SOFCs can be fuelled with reformed hydrocarbon fuels or syngas, and can theoretically utilize natural gas directly. Like the MCFC, the high operating temperature of the SOFC will allow direct reforming of natural gas in the fuel cell by utilizing the steam and the heat produced by the cell to support the reforming reaction.

.5 SOFCs have fewer problems related to corrosion, cathode dissolution or loss of electrolyte than fuel cells with liquid electrolytes. On the other hand, the SOFC must be designed and operated to minimize damage to the ceramic materials.

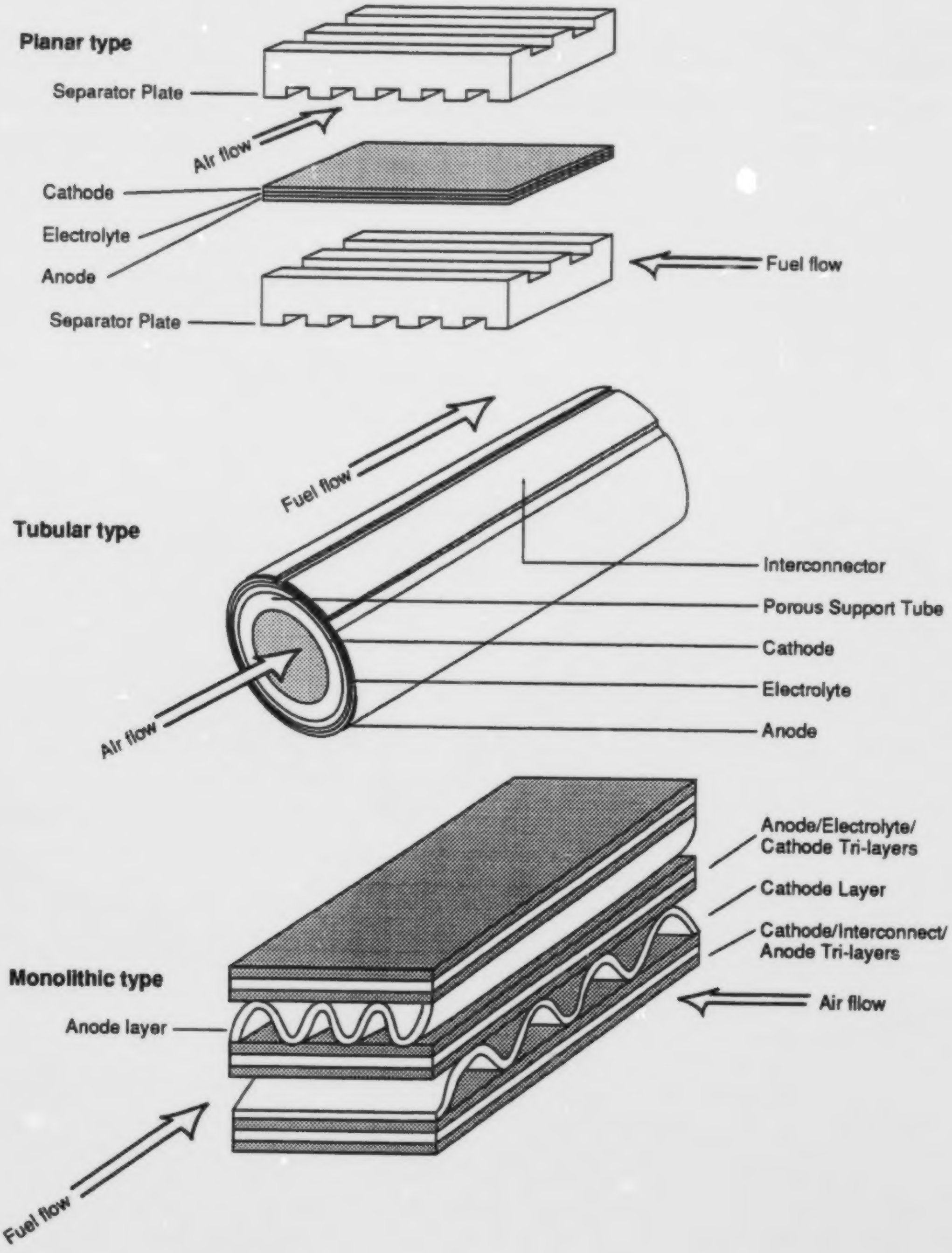
.6 As a result of the "all-solids" nature of SOFC it can be configured in a number of different physical arrangements as shown in Figure 3-3-3:

- the conventional planar or "flat-plate" design,
- a tubular design, or
- a "monolithic" (i.e., honeycomb) design.

.7 Of the three designs, Westinghouse has developed the tubular concept to the point where 20 kW units have been built and tested.

.8 The planar design is not as well developed but is potentially cheaper to fabricate.

*Figure 3-3-3: Various Configurations of Solid Oxide Fuel Cells*


Planar type
Separator Plate
Air flow
Cathode
Electrolyte
Anode
Fuel flow
Separator Plate
Fuel flow
Tubular type
Interconnector
Porous Support Tube
Cathode
Electrolyte
Anode
Air flow
Anode/Electrolyte/
Cathode Tri-layers
Cathode Layer
Cathode/Interconnect/
Anode Tri-layers
Monolithic type
Air fllow
Anode layer
Fuel flow

.9 The monolithic design offers high capacity and performance, but may be difficult to scale up from units of a few hundred watts to larger devices.

.10 A major development issue with SOFC is the fabrication of devices which will maintain physical integrity and electrical and chemical contact at temperatures up to 1000°C.

.11 SOFC is a developing technology and issues related to fabrication methods and cost reductions must be addressed. The U.S. Department of Energy, the Gas Research Institute and a number of Japanese gas and electrical utilities have supported this technology.

## 3-4 Experience

### 3-4-1 Introduction

.1 This section describes experience and developments in fuel cell technologies. Separate sections, 3-4-2, 3-4-3 and 3-4-4, document Canadian, Ontario and specific Ontario Hydro experience.

### 3-4-2 World Experience

.1 Fuel cell research and development is funded primarily by the U.S., Japan, and the European Community.

.2 The U.S. is acknowledged to be the leader in fuel cell R&D. The U.S. Department of Energy, the Gas Research Institute and the Electric Power Research Institute (EPRI) have been funding technology development of fuel cell systems for terrestrial applications for more than 10 years. Private sector activities have been ongoing for approximately 30 years. (Fuel Cell Implementation Committee, 1990)

.3 In 1981 the Japanese, through the New Energy and Industrial Technology Development Organization, implemented a 15-year fuel cell R&D program as part of their large scale energy conservation project (the Moonlight Project). The Japanese have established targets for fuel cell energy supply which amount to approximately 1,900 MW of fuel cell power plant capacity by the year 2000, and 8,200 MW of fuel cell capacity by the year 2010. (Sugimato, 1990)

.4 The European Community has been involved in the development of the low temperature fuel cell technologies, primarily for transportation applications. It has only recently formulated a program for the development and testing of medium and high temperature fuel cell technologies.

.5 Canadian R&D efforts, supported by various departments of the federal government have also focused on low temperature fuel cells.

.6 Figure 3-4-1 lists key developments for the five major types of fuel cell.

.7 As shown by Figure 3-4-1 the application of Alkaline and Solid Polymer fuels cells has been primarily in the space and transportation industries. Solid polymer fuel cells may prove useful for small remote electricity generation applications. (Prater, 1991)

.8 In the area of utility applications, development activities have focused on the PAFC, MCFC and SOFC fuel cell technologies.

.9 PAFC technology is the most developed. Significant development and commercialization activities continue, particularly in Japan.

.10 MCFC technology has undergone a revival as material problems have been largely resolved. This technology may receive the largest commercialization effort in the near term because of the support it is receiving from the American Public Power Association and EPRI.

.11 SOFC is also attracting significant development support as fabrication problems are being resolved. R&D efforts in the U.S, partially funded by the Japanese, have been focused on scaling up to 25 kW units. Significant development work is also currently underway in Europe on an alternative SOFC design.

.12 Compared to PAFC and MCFC technologies, SOFC technology has not received the same level of industry support. SOFC units currently tend to be more expensive. Widespread commercial use of this technology may, therefore, lag behind PAFC and MCFC technologies.

*Figure 3-4-1: Key Developments in Fuel Cell Technology*

| Fuel Cell Type | 1950's | 1960's | 1970's | 1980's | 1990's |
|---|---|---|---|---|---|
| AFC | First practical fuel cell (Bacon cell) developed for space program. | 1.2 kW AFC's used in Apollo space program (1966-78).<br>Development continued for transportation applications | → | 12 KW AFC's used in NASA Space Shuttle. | → |
| SPFC | | First fuel cell to be used in U.S. Space Program (Gemini), early 1960's. | Development continued, but with minimal funding for utility applications. | Canadian firm (Ballard Power Systems) established breakthrough with new polymer.<br>1st demonstration of 5KW unit at DOW chlor-alkali plant in Sarnia, Ontario.<br>Interest in technology revives. | Development continues, focused primarily on transportation applications. |
| PAFC | | Significant U.S. R&D effort because of capability to run on hydrocarbon fuels. | First demonstration units.<br>12.5 KW units demonstrated in U.S., Canada (Hydro Quebec) and Japan.<br>Development of larger units (e.g. 40 KW, and larger) by several U.S. companies. | R&D efforts increased, focused on development of larger plants.<br>40 kW units demonstrated in the U.S. and Canada. Hydro Quebec and BC Hydro were involved in this demonstration.<br>Two 4.8 MW plant demonstrations take place (in New York City and Toyko).<br>Japanese launch the "Moonlight Project" in early 1980's. Two 1 MW PAFC power plants demonstrated as well as a number of 50-200 KW plants.<br>A U.S. firm (International Fuel Cells) begins to commercialize a 200 KW sized fuel cell power plant and receives over 50 orders. | Commercialization efforts continue.<br>Toyko Electric Power Company (TEPCO) to install and operate first utility-scale plant (11MW).<br>Japanese companies building commercial manufacturing facilities for smaller units.<br>1MW PAFC power plant demonstrated in Italy.<br>IFC in U.S. building and installing 200 kW units.<br>Southern California Gas establishes first "Energy Service" company utilizing 200 kW PAFC units for the supply of both electricity and heat to customers. |
| MCFC | | U.S. DOE launches R&D efforts, spurred on by potential use of coal as a fuel and potentially high efficiencies using hydrocarbon fuels. | Developments hampered by material problems. | Material problems potentially overcome.<br>10 kW units tested in both the U.S. and Japan.<br>American Public Power Association selects MCFC technology as most attractive for utility scale applications in the near term. | R&D efforts increased, focused on scale-up and demonstration.<br>7 kW unit demonstration in Denmark.<br>Development and demonstration of 100 kW units in both Japan and the U.S.<br>2 MW demonstration plant planned for California (1993). |
| SOFC | Process identified by Westinghouse | Limited development undertaken, driven by use of coal as a fuel, and potentially high efficiencies using hydrocarbon fuels. | R&D on fabrication supported by DOE.<br>Westinghouse develops fabrication processes required to construct cells. | Westinghouse makes dramatic strides with its "tubular" design in the later half of the 1980's.<br>400 W and 5 kW Westinghouse units demonstrated at Tennessee Valley Authority (TVA).<br>Two 3 kW units built by Westinghouse and field tested by Japanese gas utilities.<br>20 kW unit built by Westinghouse and run on natural gas.<br>Argonne National Lab develops "monolithic" design - which offers high performance capability. Fabrication/scaling difficulties encountered. | 25 KW Westinghouse unit to be delivered to Kansai Electric in 1991.<br>100 KW Westinghouse unit to be demonstrated in California.<br>100-200 KW field test units planned for mid-90's.<br>Development efforts undertaken by both the Japanese and the European Community for alternative designs to the Westinghouse tubular concept. |

### 3-4-3 Canadian Experience

.1 Hydro Quebec was the first Canadian electrical utility to actively evaluate fuel cells with the purchase and testing of six 12.5 kW phosphoric acid fuel cell units in 1972.

.2 In the early 1980s Hydro Quebec began investigating the feasibility of hydrogen production by electrolysis of water as a means of energy storage. In 1984 Hydro Quebec purchased a 40 kW phosphoric acid fuel cell power plant designed to run on hydrogen. However, budget cuts prevented Hydro Quebec from testing the complete hydrogen production/storage/utilization cycle.

.3 Hydro Quebec performed a study for the Canadian Electrical Association to assess the fuel processing options available for fuel cells in communities remote from electrical grids. Methanol was identified as a potentially viable fuel. (Belanger, 1989)

.4 British Columbia Hydro (BC Hydro) has also been investigating the use of fuel cells in utility systems since the early 1970s.

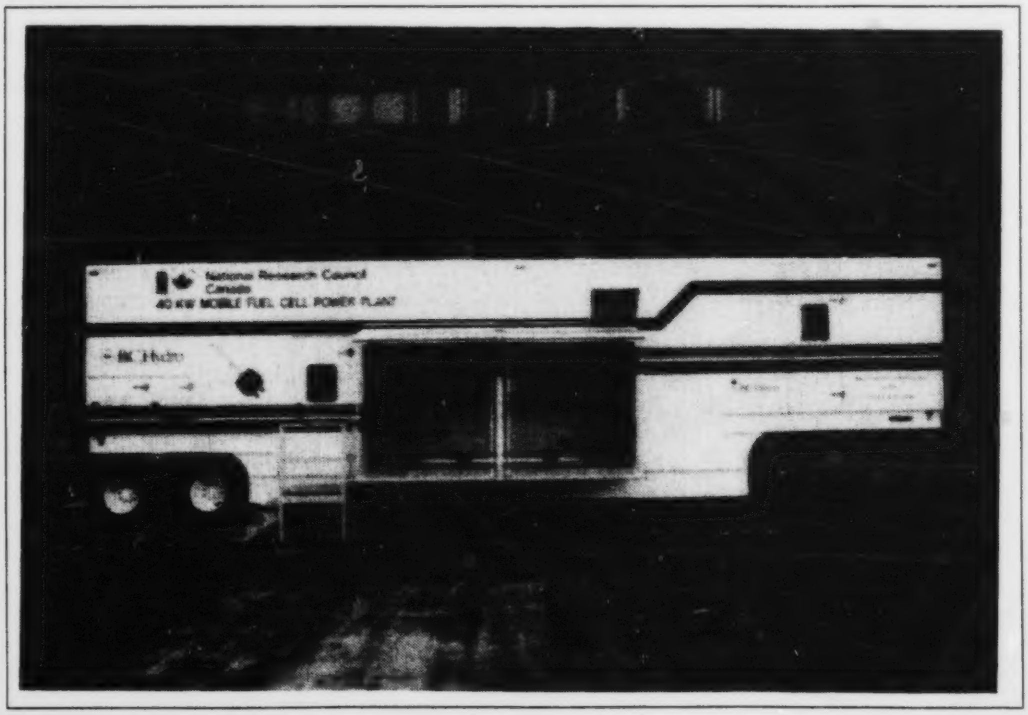
.5 In the early 1980s BC Hydro received support from Energy, Mines and Resources (EMR), the National Research Council of Canada (NRCC), Ontario Hydro and a number of gas utilities to purchase and test a 40 kW PAFC power plant designed to run on natural gas (see Figure 3-4-2).

.6 Between November 1985 and April 1987 successful testing of the unit was carried out at BC Hydro's research labs, in both "grid-isolated" and "grid-connected" modes of operation.

.7 The 40 kW PAFC power plant demonstrated conversion efficiencies of 39 to 40 percent. On average an additional 38.5 percent of the fuel energy can be recovered as heat for an overall efficiency of 77.5 percent. (Papic, 1987, 1989)

.8 Canada has established a reputation in the development of solid polymer fuel cells. Since 1984 Ballard Power Systems of North Vancouver B.C. has been working towards the commercialization of SPFC systems. (Prater, 1991)

***Figure 3-4-2: Mobile 40 kW Phosphoric Acid Fuel Cell Power Plant [Papic, 1987]***



.9 The original Ballard SPFC design uses a Nafion (Dupont tradename) membrane. However, in 1987 Ballard reported significantly higher performance using an experimental Dow membrane as the electrolyte.

.10 A 10 kW Ballard SPFC unit is currently under test at the Dow plant in Sarnia. It uses hydrogen by-products from one of the plant processes.

.11 In November 1990 Ballard Power Systems received federal funding to help it commercialize its solid polymer fuel cell.

.12 Soon after, as part of a U.S. DOE alternative fuels/electric vehicle project, Ballard received a contract to supply four 10 kW fuel cells to General Motors Corporation for an electric vehicle fuelled with methanol.

### 3-4-4 Ontario Experience

.1 In the early 1980s the Institute of Hydrogen Systems (IHS) was established with funding support from the Ontario Ministry of Energy, and EMR.

.2 Development work on alkaline fuel cells was undertaken under the auspices of the IHS, until funding was cut in 1984.

.3 Astris Corp., a private company, was formed after the demise of the IHS and continues, with government funding support, to develop alkaline fuel cell technology.

.4 In 1988, the Ontario Ministry of Energy, Ballard Power Systems and Dow Chemical Canada Inc. initiated a joint project to test and demonstrate two 5 kW solid polymer fuel cells at Dow's chlor-alkali plant in Sarnia, Ontario. (Ontario Ministry of Energy, 1988). The demonstration is still underway.

### 3-4-5 Ontario Hydro Experience

.1 Ontario Hydro provided partial funding the 40 kW PAFC demonstration and test program conducted by BC Hydro from 1986 to 1988 (previously discussed in Section 3-4-3).

.2 In 1991 Ontario Hydro obtained the 40 kW PAFC power plant from BC Hydro for use in demonstration programs.

.3 Ontario Hydro staff acted as monitors of Hydro Quebec's study of "Fuel Reforming for Fuel Cells in Remote Locations", done for the CEA. (CEA, 1989)

.4 In 1990 Ontario Hydro established a fuel cell task group to examine and explore opportunities for obtaining and demonstrating fuel cell technologies in Ontario.

.5 Ontario Hydro has provided funding to Westinghouse to perform a concept design study of solid oxide fuel cell power plants for use in Ontario. This report should be completed in 1991.

.6 Ontario Hydro has joined two inter-utility groups to gain a "window" on the development of MCFC technology.

### 3-5 Potential System Application

.1 Interest in the fuel cell as a utility power plant results mainly from its high efficiency at full and part loads, its low pollutant emissions and noise, and its modular configuration. Other features for consideration include load following ability, and in some cases, the ability to supply additional power for peaking at slightly decreased overall fuel efficiency.

.2 A fuel cell power plant intended for utility use requires a power conditioner to convert the direct current from the fuel cell to alternating current for the grid as shown in Figure 3-1-4.

.3 Depending on the fuel cell type a fuel processor may be required to convert a utility fuel such as natural gas to a hydrogen rich gas.

.4 A fuel cell power plant can be located in the area it serves because of its low noise, low environmental emissions and low water requirements. If used within a commercial or industrial building it also reduces required distribution capacity.

.5 Modularity enables: (1) the addition of relatively small blocks of capacity to match the growth of demand, and (2) the dispersal of the units to reduce transmission costs.

.6 The fuel cell has the potential to serve utilities in several ways, as shown in Figure 3-5-1 and summarized in Figure 3-5-2.

*Figure 3-5-1: Three Possible Fuel Cell Roles in Utility Applications*

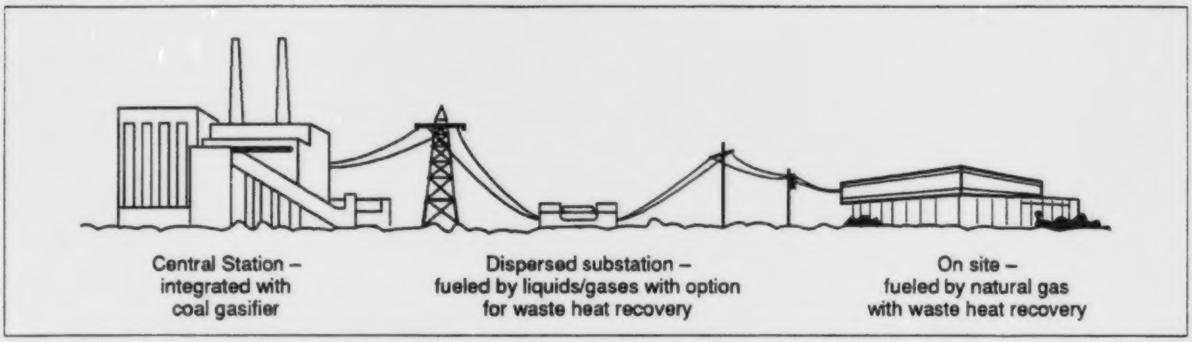


*Figure 3-5-2: Utility Fuel Cell Power Plants – Markets of Interest*

| Applications | Size range | Fuels |
|---|---|---|
| Remote communities | 50 - 1000 kW | Methanol, naphtha |
| On-site, residential: Single and multi-unit | 5 - 1000 kW | Natural gas, electrolytic hydrogen |
| On-site, commercial | 50 - 2000 kW | Natural gas |
| Industrial cogeneration | 2 - 20 MW | Natural gas<br>by-product gasses |
| Electric utility, dispersed | 5 - 50 MW | Natural gas<br>coal-derived gases |
| Electric utility, base load | 100 - 600 MW | Natural gas, coal-derived gases |

.7 Small power plants (5 kW to 2 MW capacity) could power single or multi-unit residential or commercial buildings. Natural gas is the most readily available fuel for this type of application.

.8 Small fuel cell power plants could also supply power in remote communities not connected to the main grid. Such plants would use either methanol or naphtha fuel. These fuels can be transported by air, a requirement for many remote Ontario communities.

.9 Larger plants, ranging in size from 5 to 25 MW could be dispersed throughout an electrical utility system to provide electricity on demand (load-following), because of their high operating efficiency over a wide load range. In this type of application the capacity factor could range from 30 to 100 percent. Such plants are expected to use either natural gas or coal-derived gases as fuel.

.10 Both low temperature and high temperature fuel cell plants can be used for industrial cogeneration (providing both electric and thermal energy) with overall efficiencies up to 80 percent. The heat produced from high temperature MCFC and SOFC power plants can be used to produce steam in heat recovery steam generators. This steam can be used for process heat in cogeneration applications or for additional electricity generation. Industrial cogeneration fuel cells could use byproduct gases or natural gas as their fuel.

.11 Beyond the year 2000 large fuel cell plants (approximately 100 to 800 MW) may be integrated with coal gasifiers to provide large, centralized, base load power generation. Such plants would use an integrated, combined cycle configuration with a steam bottoming cycle in order to achieve maximum efficiency (approximately 45 percent).

## 3-6 Environmental Considerations

.1 This section of the review discusses environmental considerations, both natural and social, associated with fuel cell technologies.

.2 While there are environmental concerns and potential safety hazards associated with the production of fuel cells, the management of environmental effects associated with prefabrication is assumed to be included in the price of the items, and is not addressed in detail.

### 3-6-1 Natural Environment

.1 This section discusses environmental and safety issues associated with fuel cell technologies and their impact on the natural environment under the headings of air, land, water and other.

*Air*

.2 When fuelled with pure hydrogen fuel cells produce only electricity, water and heat.

.3 Other fuels (e.g., natural gas) may produce emissions which include $CO_2$, $NO_x$, CO, $SO_2$ and particulates. $NO_x$, CO and particulate emissions result primarily from fuel processing and are minimal. $SO_2$ emissions are minimal since sulphur must be removed (as a solid waste) from the fuel prior to utilization in the fuel cell. (Fickett, 1984). High fuel cell efficiencies result in lower rates of $CO_2$ emissions per kWh compared to conventional fossil-fuelled generation.

*Land*

.4 Fuel cell facilities are relatively compact. Land requirements for fuel cell power plants in the size range from 200 kW to 20 MW vary from approximately $0.1 m^2/kW$ to $0.3 m^2/kW$, depending on the fuel cell type, and the amount of auxiliary heat recovery equipment included in the power plant. (IFC, 1986; GRI, 1989; TEPCO, 1991; FCCG, 1990; OH, 1991)

.5 Fuel processing is the primary potential source of solid waste. Waste generation will depend on the fuel used and the fuel processing technology adopted.

.6 Two proven techniques can be used to remove residual sulphur from natural gas for PAFC, MCFC, and SOFC technologies – zinc oxide (ZnO) beds for small fuel cell power plants, and hydrodesulphurization systems for larger fuel cell power plants. Zinc oxide reacts with the sulphur to produce zinc sulphide. The amount of zinc sulphide produced is relatively small, in the order of $0.04 m^3/yr$ for a 200 kW fuel cell (GRI, 1989). It is possible to return the zinc sulphide to the supplier for regeneration.

.7 Spent catalyst, where used during fuel processing (e.g., steam reforming, hydrodesulphurization), would require disposal or regeneration. Steam reforming of natural gas is usually carried out over a nickel or iron-containing catalyst while hydrodesulphurization utilizes a cobalt-molybdenum catalyst. (Appleby, 1989). The amounts of catalyst to be disposed of would be relatively small.

.8 Coal gasification generates solid wastes. The nature and composition of these wastes depend on the composition of the coal and the gasification process employed. The volume of solid waste produced by a gasification-based plant is less than half that of a conventional coal plant with scrubbers, and the product is an inert slag that can be used as a construction material. (Douglas, 1990)

.9 The wastes generated upon decommissioning a fuel cell facility depend on the technology used.

- Phosphoric acid fuel cells would be recycled to the vendor for recovery of the platinum catalyst in the electrode.
- MCFC technology requires disposal of a lithium-aluminate matrix. This material is in the form of an inert ceramic at ambient temperatures and should not represent a environmental problem. Nickel electrodes can be recycled.
- SOFC technology requires the disposal of rare earth elements. However, those materials would be in the form of an inert ceramic matrix at ambient conditions.

.10 Decommissioning of the remainder of the fuel cell facility should be similar to decommissioning a conventional power plant.

*Water*

.11 Fuel cells do not require large amounts of water. Sufficient quantities of water to meet operational requirements are normally produced in the fuel cell reaction.

.12 Blowdown water from the small steam generator required to raise steam for the steam reforming process is the primary potential source of effluent.

.13 The heat produced by MCFCs and SOFCs operating at temperatures from 650°C to 1000°C can be used to produce steam in a heat recovery steam generator. This steam can be used for process heat in cogeneration or combined cycle applications. In combined cycle applications cooling water requirements per MW of steam-generated electricity would be comparable to the water requirements for a conventional steam-electric cycle (e.g., see Appendix B).

.14 The heat produced by PAFCs, which operate in the range of 205°C, could be used for water heating applications resulting in better utilization of the energy content of the fuel. Cooling water requirements for PAFCs would be minimal.

.15 Coal gasification requires waste water treatment to remove a wide range of pollutants, including residual heavy hydrocarbons, phenols, ammonia and trace metals.

*Other*

.16 Safety concerns regarding fuel cell facilities are primarily related to the fuel. (Gelfond and Yale, 1984). Fuel leakage presents a risk of fire or explosion, with related hazards such as smoke inhalation, asphyxiation and CO poisoning.

*Summary*

.17 Fuel cells are an environmentally promising technology. However, there are environmental concerns to address. Specific concerns depend on the choice of fuel and technology.

.18 Fuel cells using hydrocarbon fuels may offer a number of environmental advantages over conventional fossil-fuelled generation, including reduced atmospheric emissions of $CO_2$, $NO_x$, $SO_2$ and particulates, and, in the case of the higher temperature MCFC and SOFC technologies, better use of the energy content of the fuel in combined cycle or cogeneration applications.

.19 While processing of hydrocarbon fuels to produce hydrogen will contribute to atmospheric $CO_2$ loading, high fuel cell efficiencies result in lower $CO_2$ emissions per kWh compared to conventional fossil-fuelled generation.

### 3-6-2 Social Environment

.1 This section discusses issues associated with fuel cell technologies and their impact on the social environment under the headings of socio-economic effects and societal considerations.

*Socio-Economic Effects*

.2 Fuel cells are ideally suited for use at dispersed locations close to the loads (e.g., located in individual households and factories) because of their modularity, efficiency and low emissions. Local community impacts could consequently be minimized because of the need for fewer transmission lines and the ability to reduce the amount of land required for energy production.

.3 Some fuel cell technologies have the potential to produce both electricity and usable thermal energy (combined cycle, cogeneration, district heating, or hot water applications). This feature could be attractive to new and existing industries and could provide local/regional economic stimulus.

.4 Small fuel cells dispersed throughout the province may create employment opportunities within the installation and maintenance sectors. Larger plants dispersed throughout the province may provide limited local employment involving skills on par with the skills required by utilities.

.5 There is not presently an industrial infrastructure supporting the manufacture of fuel cells in Ontario. As a result, regional economic development opportunities associated with the manufacture of fuel cells are currently minimal. As fuel cells are a rapidly evolving technology the potential exists for additional employment and economic development opportunities associated with the development of the full infrastructure of the fuel cell.

*Societal Considerations*

.6 Fuel cells may offer a number of environmental advantages over conventional fossil-fuelled generation, including reduced atmospheric emissions of $CO_2$, $NO_x$, $SO_2$ and particulates, as well as minimal waste products. Fuel cells are therefore likely to receive a higher degree of social acceptance from members of the general public.

.7 Use of natural gas as a fuel is well accepted by society. However, some sensitive groups may have safety concerns (e.g., related to explosions) about the conversion of natural gas and other fuels to hydrogen within the fuel cell in order to generate electricity.

.8 The risks associated with fuel cells are minimal and local while the benefits are anticipated to be both local and provincial.

.9 Social impacts because of construction and operation would depend upon whether the technology was implemented as dispersed or centralized generation.

## 3-7 Operational Considerations

.1 Fuel cell power plants in the 200 kW to 10 MW range are being designed to operate unattended. Little experience is available today.

.2 Maintenance costs will be related mainly to periodic replacement of fuel cell stacks (once every several years) and water treatment systems. Other maintenance would be on an as needed basis, much as electrical utilities service transformer stations and gas utilities service gas appliances.

## 3-8 Development Issues

.1 The electrochemical reaction in a fuel cell requires a precise interaction between a gas (either the fuel or oxidant at the respective electrodes), the electrolyte, and the electrodes. Only with the advent of improved understanding of materials have practical gas diffusion electrodes been developed which have led to practical, long-running devices.

.2 Some fuel cell technologies are well developed for niche applications such as the space program.

.3 A primary issue in fuel cell development for utility applications is materials compatibility and durability. This consideration is particularly important in cells which operate at high temperatures such as MCFC and SOFC.

.4 Scaled up designs for utility applications are yet to be demonstrated.

.5 The challenge is to develop the materials and components that can withstand the operating conditions imposed by the electrolyte in order to permit the reliable operation of large scale fuel cells for tens of thousands of hours. For example, electrolyte or gas leaks must be avoided in some fuel cell types.

.6 Another key issue is the development of improved electrolytes which will maintain separation of fuel and oxidant gas at higher pressures, thereby permitting higher efficiency operation.

.7 Without further development of fuel reformer technologies and gas cleaning systems those fuel cells which must operate on pure hydrogen will have limited application potential.

.8 Figure 3-8-1 indicates the American Public Power Association's best estimate schedule for the introduction of demonstration, market entry and fully commercially mature PAFC, MCFC, and SOFC units. (Bergman and Serfass, 1990)

.9 Two groups have been formed in the U.S. to develop commercial MCFC units by 1994. Commercial SOFC units will probably follow within several years.

## 3-9 Options Selected for Costing

### 3-9-1 Introduction

.1 The options selected for preparing representative costs of using fuel cells for electricity generation in Ontario are discussed below.

*Figure 3-8-1: Development and Timing Issues for Fuel Cell Technology [after Bergman and Serfass, 1990]*

| Technology | System complexity | Readiness and timing | Year estimated for | | |
|---|---|---|---|---|---|
| | | | Demo | Entry | Mature |
| Phosphoric acid | Complex | Early to mid 1990's | 1992-1993 | 1994 | 1996 |
| Molten carbonate | Simplest | Mid to late 1990's | 1993 | 1995 | 1997 |
| Solid oxide | Simple | Late 1990's | 1995 | 1997 | >1997 |

### 3-9-2 On-Site 200 kW Option

.1 The on-site option would be a 200 kW phosphoric acid fuel cell, molten carbonate fuel cell or solid oxide fuel cell power plant fuelled by natural gas.

.2 Why select a 200 kW PAFC, MCFC or SOFC? These plants can use a readily available fuel (natural gas), supply both useable heat and electricity, and are of suitable size for connection to loads such as multi-residential units, hotels, and nursing homes.

.3 This option would normally be installed in a cogeneration application producing both electricity and useable heat.

.4 Why select natural gas as a fuel? Natural gas is readily available in Ontario. Propane could be used as a fuel where natural gas supply is not available.

### 3-9-3 Dispersed Utility or Industrial Scale 10 MW Option

.1 The dispersed utility or industrial scale option would be a 10 MW phosphoric acid fuel cell, molten carbonate fuel cell or solid oxide fuel cell plant fuelled by natural gas.

.2 This option would normally be installed in a cogeneration application producing both electricity and useable heat, for example, for process or district heating.

.3 Why select a 10 MW PAFC, MCFC, or SOFC plant? For the industrial and dispersed utility markets power plants ranging in size from 5 to 50 MW are conceivable. A unit size of 10 MW was selected as representative.

.4 PAFCs, MCFCs and SOFCs can also supply useable heat for cogeneration or district heating.

.5 Why select natural gas as a fuel? Natural gas is readily available in Ontario.

### 3-10 Costs and Performance

.1 This section discusses the performance and cost assumptions used to estimate the levelized unit energy costs for the 200 kW and 10 MW fuel cell options considered.

.2 These two sizes of plants, used in combination with the three major fuel cell types, result in a total of six options, as shown below:

*Option 1:* 200 kW phosphoric acid fuel cell power plant
*Option 2:* 10 MW phosphoric acid fuel cell power plant
*Option 3:* 200 kW molten carbonate fuel cell power plant
*Option 4:* 10 MW molten carbonate fuel cell power plant
*Option 5:* 200 kW solid oxide fuel cell power plant
*Option 6:* 10 MW solid oxide fuel cell power plant

### 3-10-1 Performance Assumptions

.1 Figure 3-10-1 below summarizes the performance assumptions used in evaluating the levelized unit energy cost of the fuel cell options.

.2 The design life of the smaller fuel cell systems is 20 years based on current manufacturers' estimates. The design life for the larger cell systems is expected to be 30 years.

.3 All of the options would be fuelled with natural gas. The efficiencies quoted are based on the higher heating value of natural gas.

### 3-10-2 Cost Estimates

.1 Ontario Hydro has no direct experience with the design, construction, installation and operation of fuel cell power plants.

.2 Thus, the cost estimates are based mainly on surveys of manufacturers and on industry surveys regarding costs and cost trends. Cost estimates are based on the most current information available to Ontario Hydro. The costs are intended to provide an indication of a range of costs and not a definitive estimate of the cost of each option.

.3 The cost estimates for the PAFC options are presented as both current (1991) costs and projected year 2000 costs. PAFC power plants are commercially available today; thus, it is appropriate to present 1991 cost estimates.

.4 The cost estimates for the MCFC and SOFC options are presented only as projected year 2000 costs. These types of fuel cells are not commercially available today; thus, 1991 cost estimates are not meaningful.

.5 The costs presented are those for electricity as the only product. Section 3-10-5 shows the potential value of the useable heat for each of the six fuel cell options, given the assumptions about the amount and value of the heat discussed in Part 1, Section 1-7.

.6 Capital, OM&A and fuel cost estimates for the six fuel cell options are shown in Figures 3-10-2 and 3-10-3 below.

***Figure 3-10-1: Fuel Cell Performance Assumptions***

| Option | Description | Useful Life (yrs.) | Annual Capacity Factor (%) | Thermal Efficiency (%) |
|---|---|---|---|---|
| 1 | 200 kW PAFC | 20 | 80 | 36.4 |
| 2 | 10 MW PAFC | 30 | 80 | 41.1 |
| 3 | 200 kW MCFC | 20 | 80 | 49.1 |
| 4 | 10 MW MCFC | 30 | 80 | 54.5 |
| 5 | 200 kW SOFC | 20 | 80 | 41.7 |
| 6 | 10 MW SOFC | 30 | 80 | 51.9 |

*Figure 3-10-2: Cost Estimates – 200 kW Fuel Cell Options*

| Cost Component | Phosphoric Acid | | Molten Carbonate | | Solid Oxide | |
|---|---|---|---|---|---|---|
| | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs |
| Initial Capital ($/kw) | 4,800 | 2,950 | N/A | 2,175 | N/A | 2,675 |
| Later Capital ($/kW/yr) | 5 | 5 | N/A | 53 | N/A | 50 |
| OM&A ($/kW/yr) | 140 (1) | 55 (1) | N/A | 47 | N/A | 47 |
| Fuel (¢/kWh) | 2.78 | 2.78 | N/A | 2.06 | N/A | 2.42 |

(1) Includes fuel cell stack replacement costs. Fuel cell stack replacement costs are included in Later Capital for all other applications.
N/A = Not applicable.

*Figure 3-10-3: Cost Estimates – 10 MW Fuel Cell Options*

| Cost Component | Phosphoric Acid | | Molten Carbonate | | Solid Oxide | |
|---|---|---|---|---|---|---|
| | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs | 1991 Costs | 2000 Costs |
| Total Capital ($/kw) | 4,805 | 1,603 | N/A | 2,003 | N/A | 2,353 |
| Later Capital ($/kW/yr) | 53 | 15 | N/A | 54 | N/A | 49 |
| OM&A ($/kW/yr) | 63 | 63 | N/A | 27 | N/A | 27 |
| Fuel (¢/kWh) | 2.24 | 2.24 | N/A | 1.69 | N/A | 1.77 |

N/A = Not applicable.

### 3-10-3 Levelized Unit Energy Cost Summary

.1 The levelized unit energy costs obtained using the performance and cost estimates shown above are summarized below in Figures 3-10-4 and 3-10-5 for the 200 kW and 10 MW options respectively.

### 3-10-4 Sensitivity Ranges

.1 For each option, the sensitivities of the levelized unit energy cost to variations in the values of the individual cost components, in economic factors and in performance, are presented. Sensitivity analyses provide an indication of the variability of the levelized unit energy cost to changes in cost and performance assumptions.

.2 The cost estimates for fuel cell power plants are subject to large uncertainties, particularly when considering projected year 2000 costs. These large uncertainties are reflected in the sensitivity ranges chosen.

.3 The sensitivity ranges selected are not intended to reflect a particular confidence level. The level of information available does not lend itself to such a detailed analysis. They simply represent Ontario Hydro's judgement of the possible variation of these factors.

*Figure 3-10-4: Levelized Unit Energy Cost Estimates – 200 kW Fuel Cell Options*

| Cost Component | Phosphoric Acid 1991 Costs | Phosphoric Acid 2000 Costs | Molten Carbonate 1991 Costs | Molten Carbonate 2000 Costs | Solid Oxide 1991 Costs | Solid Oxide 2000 Costs |
|---|---|---|---|---|---|---|
| | **Levelized Unit Energy Cost (LUEC) Estimates at 80% ACF (¢/kWh)** | | | | | |
| Total Capital | 6.2 | 3.8 | N/A | 3.6 | N/A | 4.2 |
| OM&A | 2.4 [(1)] | 0.9[(1)] | N/A | 0.8 | N/A | 0.8 |
| Fuel | 5.5 | 5.5 | N/A | 4.1 | N/A | 4.8 |
| Total LUEC | 14.1 | 10.2 | N/A | 8.5 | N/A | 9.8 |

(1) Includes fuel cell stack replacement costs. Fuel cell stack replacement costs are included in Later Capital for all other options.

*Figure 3-10-5: Levelized Unit Energy Cost Estimates – 10 MW Fuel Cell Options*

| Cost Component | Phosphoric Acid 1991 Costs | Phosphoric Acid 2000 Costs | Molten Carbonate 1991 Costs | Molten Carbonate 2000 Costs | Solid Oxide 1991 Costs | Solid Oxide 2000 Costs |
|---|---|---|---|---|---|---|
| | **Levelized Unit Energy Cost (LUEC) Estimates at 80% ACF (¢/kWh)** | | | | | |
| Total Capital | 6.0 | 1.9 | N/A | 3.0 | N/A | 3.3 |
| OM&A | 1.1 | 1.1 | N/A | 0.5 | N/A | 0.5 |
| Fuel | 4.5 | 4.5 | N/A | 3.4 | N/A | 3.6 |
| Total LUEC | 11.6 | 7.5 | N/A | 6.9 | N/A | 7.4 |

.4 Figures 3-10-6 to 3-10-9 show the sensitivity ranges selected for costs and performance and the effect of those ranges on the levelized unit energy costs for the six options assessed.

.5 Given the assumptions in this report regarding costs and performance, the largest range of levelized unit energy costs for each option can be obtained by assuming that all cost components and performance factors are fully dependent. That is, if one cost component increases, all cost components are assumed to increase and all performance factors are assumed to decrease, and vice-versa. In this manner, an indication of the upper and lower ranges of the levelized unit energy costs for each option is obtained. These upper and lower estimates are shown in Figures 3-10-10 and 3-10-11.

### 3-10-5 Potential Value of Useable Heat

.1 The economic evaluations shown above consider electricity as the only product. Fuel cell power plants would normally be expected to be installed in cogeneration applications producing both electricity and useable heat. Revenues from the use or sale of heat could partially offset electricity production costs.

.2 The potential value of the useable heat produced, expressed as a levelized unit energy benefit (LUEB) in cents per kilowatt-hour, is shown in Figure 3-10-12 for each of the six fuel cell options.

***Figure 3-10-6: Cost Component Sensitivities – 200 kW Fuel Cell Options***

| Cost Component | LUEC at 80% ACF (¢/kWh) | Range Assumed (%) | | Sensitivity (%)* | |
|---|---|---|---|---|---|
| | | Lower | Upper | Lower | Upper |
| **Option 1 – PAFC (1991 Costs)** | | | | | |
| Capital | 6.2 | -20 | +20 | -8.8 | +8.8 |
| OM&A | 2.4 | -10 | +15 | -1.7 | +2.6 |
| Fuel | 5.5 | -10 | +10 | -3.9 | +3.9 |
| Total | 14.1 | | | -14.4(1) | +15.3(1) |
| **Option 1 – PAFC (2000 Costs)** | | | | | |
| Capital | 3.8 | -10 | +30 | -3.7 | +11.2 |
| OM&A | 0.9 | -10 | +15 | -0.9 | +1.3 |
| Fuel | 5.5 | -10 | +10 | -5.4 | +5.4 |
| Total | 10.2 | | | -10.0(1) | +17.9(1) |
| **Option 3 – MCFC (2000 Costs)** | | | | | |
| Capital | 3.6 | -10 | +50 | -4.2 | +21.1 |
| OM&A | 0.8 | -10 | +15 | -1.0 | +1.4 |
| Fuel | 4.1 | -10 | +10 | -4.8 | +1.4 |
| Total | 8.5 | | | -10.0(1) | +27.3(1) |
| **Option 5 – SOFC (2000 Costs)** | | | | | |
| Capital | 4.2 | -10 | +50 | -4.3 | +21.4 |
| OM&A | 0.8 | -10 | +15 | -0.8 | +1.2 |
| Fuel | 4.8 | -10 | +10 | -4.9 | +4.9 |
| Total | 9.8 | | | -10.0(1) | +27.3(1) |

***Figure 3-10-7: Cost Component Sensitivities – 10 MW Fuel Cell Options***

| Cost Component | LUEC at 80% ACF (¢/kWh) | Range Assumed (%) | | Sensitivity (%) * | |
|---|---|---|---|---|---|
| | | Lower | Upper | Lower | Upper |
| **Option 2 – PAFC (1991 Costs)** | | | | | |
| Capital | 6.0 | -20 | +20 | -10.3 | +10.3 |
| OM&A | 1.1 | -10 | +15 | -1.0 | +1.5 |
| Fuel | 4.5 | -10 | +10 | -3.9 | +3.9 |
| Total | 11.6 | | | -15.1(1) | +15.6(1) |
| **Option 2 – PAFC (2000 Costs)** | | | | | |
| Capital | 1.9 | -10 | +30 | -2.5 | +7.7 |
| OM&A | 1.1 | -10 | +15 | -1.5 | +2.2 |
| Fuel | 4.5 | -10 | +10 | -6.0 | +6.0 |
| Total | 7.5 | | | -10.0(1) | +15.9(1) |
| **Option 4 – MCFC (2000 Costs)** | | | | | |
| Capital | 3.0 | -10 | +50 | -4.4 | +21.8 |
| OM&A | 0.5 | -10 | +15 | -0.7 | +1.0 |
| Fuel | 3.4 | -10 | +10 | -4.9 | +4.9 |
| Total | 6.9 | | | -10.0(1) | +27.8(1) |
| **Option 6 – SOFC (2000 Costs)** | | | | | |
| Capital | 3.3 | -10 | +50 | -4.4 | +22.5 |
| OM&A | 0.5 | -10 | +15 | -0.7 | +1.0 |
| Fuel | 3.6 | -10 | +10 | -4.9 | +4.9 |
| Total | 7.4 | | | -10.0(1) | +28.3(1) |

* Percentage change in total LUEC of each option.

(1) Total sensitivities are calculated assuming all cost components are fully dependent.

***Figure 3-10-8: Performance Sensitivities – 200 kW Fuel Cell Options***

| Factor | Point Estimate | Range Assumed | | Sensitivity (%) * | |
|---|---|---|---|---|---|
| | | Lower | Upper | Lower | Upper |
| **Option 1 – PAFC (1991)** | | | | | |
| Annual Capacity Factor | 80% | 90% | 70% | -6.8 | +8.7 |
| Life (years) | 20 | 25 | 15 | -4.1 | +7.5 |
| Thermal Efficiency | 36.4% | 37.4% | 35.4% | -1.0 | +1.1 |
| **Option 1 – PAFC (2000)** | | | | | |
| Annual Capacity Factor | 80% | 90% | 70% | -5.2 | +6.6 |
| Life (years) | 20 | 25 | 15 | -3.4 | +6.2 |
| Thermal Efficiency | 36.4% | 37.4% | 35.5% | -1.4 | +1.5 |
| **Option 3 – MCFC (2000)** | | | | | |
| Annual Capacity Factor | 80% | 90% | 70% | -5.8 | +7.4 |
| Life (years) | 20 | 25 | 15 | -2.6 | +4.6 |
| Thermal Efficiency | 49.1% | 50.1% | 48.1% | -1.0 | +1.0 |
| **Option 5 – SOFC (2000)** | | | | | |
| Annual Capacity Factor | 80% | 90% | 70% | -5.7 | +7.3 |
| Life (years) | 20 | 25 | 15 | -2.7 | +5.0 |
| Thermal Efficiency | 41.7% | 42.7% | 40.7% | -1.1 | +1.2 |

***Figure 3-10-9: Performance Sensitivities – 10 MW Fuel Cell Options***

| Factor | Point Estimate | Range Assumed | | Sensitivity (%) * | |
|---|---|---|---|---|---|
| | | Lower | Upper | Lower | Upper |
| **Option 1 – PAFC (1991)** | | | | | |
| Annual Capacity Factor | 80% | 90% | 70% | -6.8 | +8.7 |
| Life (years) | 30 | 35 | 25 | -1.8 | +2.8 |
| Thermal Efficiency | 41.1% | 42.1% | 40.1% | -0.9 | +1.0 |
| **Option 1 – PAFC (2000)** | | | | | |
| Annual Capacity Factor | 80% | 90% | 70% | -4.5 | +5.8 |
| Life (years) | 30 | 35 | 25 | -0.6 | +1.1 |
| Thermal Efficiency | 41.1% | 42.1% | 40.1% | -1.4 | +1.5 |
| **Option 3 – MCFC (2000)** | | | | | |
| Annual Capacity Factor | 80% | 90% | 70% | -5.6 | +7.2 |
| Life (years) | 30 | 35 | 25 | -0.9 | +1.6 |
| Thermal Efficiency | 54.5% | 42.1% | 40.1% | -0.9 | +0.9 |
| **Option 5 – SOFC (2000)** | | | | | |
| Annual Capacity Factor | 80% | 90% | 70% | -5.7 | +7.4 |
| Life (years) | 30 | 35 | 25 | -1.1 | +1.8 |
| Thermal Efficiency | 51.9% | 52.9% | 50.9% | -0.9 | +1.0 |

* Percentage change in total LUEC of each option.

*Figure 3-10-10: Overall Sensitivity – 200 kW Fuel Cell Options*

| Option | Overall Sensitivity – LUEC (¢/kWh) | | |
|---|---|---|---|
| | Lower Estimate | Point Estimate | Upper Estimate |
| Option 1 – PAFC (1991) | 10.8 | 14.1 | 19.4 |
| Option 1 – PAFC (2000) | 8.4 | 10.2 | 14.1 |
| Option 3 – MCFC (2000) | 7.0 | 8.5 | 12.6 |
| Option 5 – SOFC (2000) | 8.0 | 9.8 | 14.6 |

*Figure 3-10-11: Overall Sensitivity – 10 MW Fuel Cell Options*

| Option | Overall Sensitivity – LUEC (¢/kWh) | | |
|---|---|---|---|
| | Lower Estimate | Point Estimate | Upper Estimate |
| Option 2 – PAFC (1991) | 8.9 | 11.6 | 15.1 |
| Option 2 – PAFC (2000) | 6.4 | 7.5 | 9.6 |
| Option 4 – MCFC (2000) | 5.7 | 6.9 | 9.8 |
| Option 6 – SOFC (2000) | 6.1 | 7.4 | 10.5 |

*Figure 3-10-12: Potential Value of Useable Heat – Fuel Cell Options*

| Option | Description | Thermal Efficiency (%) | Useable Heat [1] (MBTU/yr) | Value of Heat LUEB (¢/kWh)[2] |
|---|---|---|---|---|
| 1 | 200 kW PAFC | 36.4 | 5,728 | 2.4 |
| 2 | 10 kW PAFC | 41.1 | 226,314 | 1.8 |
| 3 | 200 kW MCFC | 49.1 | 3,010 | 1.3 |
| 4 | 10 kW MCFC | 54.5 | 111,879 | 0.9 |
| 5 | 200 kW SOFC | 41.7 | 4,392 | 1.8 |
| 6 | 10 kW SOFC | 51.9 | 129,462 | 1.0 |

[1] Assumes 80% of energy content of fuel is recovered as either useable heat or electricity. Assumed 80% ACF.

[2] LUEB = Levelized Unit Energy Benefit.

.3 The heat is valued on the basis of Ontario Hydro's forecast of the commercial direct price of natural gas for the 200 kW options and at the industrial direct price of natural gas for the 10 MW options. In addition, as discussed in Part 1, Section 1-7, it is assumed that 80 percent of the energy content of the fuel is recovered in a cogeneration application as electricity and useable heat.

.4 In this analysis it is also assumed that no additional costs would be incurred for the installation and operation of heat recovery and distribution equipment.

.5 The results in Figure 3-10-12 show that, given the assumptions used in the above calculations, the magnitude of the potential levelized unit energy benefit for fuel cells ranges from 0.9 ¢/kWh (for the option with the highest fuel-to-electricity conversion efficiency) to 2.4 ¢/kWh (for the option with the lowest fuel-to-electricity conversion efficiency).

### 3-10-6 Cost Summary

.1 The results in Figures 3-10-10 to 3-10-11 show that, using current costs, the levelized unit energy cost of electricity from PAFC power plants range from 8.9 ¢/kWh to 19.4 ¢/kWh at 80 percent annual capacity factor. At this cost electricity production using currently available fuel cell power plants is not an economical alternative for Ontario, given that the levelized unit energy costs of conventional base-loaded generation options (for example, nuclear or conventional steam cycle coal) are projected to be in the range of 3 to 5 cents per kilowatt-hour.

.2 The results also show that the levelized unit energy cost of electricity using projected year 2000 costs would be expected to range from 6.4 ¢/kWh to 14.1 ¢/kWh for PAFC power plants, 5.7 ¢/kWh to 12.6 ¢/kWh for MCFC power plants and from 6.1 ¢/kWh to 14.6 ¢/kWh for SOFC power plants. These projected unit energy costs show a considerable reduction from 1991 costs; however, these costs are still above the costs of conventional base-loaded generation options in Ontario.

.3 The use of fuel cell power plants in combined heat and power applications could make these plants more economical since revenues from the use or sale of heat could partially offset electricity production costs.

## 3-11 Potential

### 3-11-1 Scenario Descriptions

.1 The potential for fuel cell power plants is assessed under the three scenarios described earlier in Part 1, Section 1-8. These scenario descriptions are repeated below:

*Scenario 1:* In this scenario, it is assumed that there is no improvement in current costs and technological status by the year 2000. The potential contribution by the year 2005 is assessed.

*Scenario 2:* In this scenario, an attempt is made to account for cost and technological improvements which may occur by the year 2000. Given these improvements, the potential contribution by the year 2005 is reassessed.

*Scenario 3:* The projections in this highly speculative scenario are based on assumptions that significant improvements in technology and costs could occur by the year 2010. The potential contribution by the year 2014 is assessed.

### 3-11-2 Background to Potential Contribution Estimates

.1 Fuel cells are a rapidly developing technology. Of the three major fuel cell types assessed in this report only phosphoric acid fuel cells can be considered to be commercially available. Molten carbonate fuel cells are forecast to be commercially available by the period 1995 to 2000 and solid oxide fuel cells after the year 2000.

.2 During the next 10 to 20 years natural gas will likely be the primary fuel of choice for fuel cell operation due to its ready availability, ease of use, and cost.

.3 Fuel cell power plants will most likely first become cost-effective in combined heat and power applications. The production and sale of heat could reduce the effective cost of the electricity produced by the plant.

.4 Due to the high efficiency, modularity, quiet operation and low emissions of fuel cell power plants, as well as their capability to serve the energy needs of the customer on-site, siting of fuel cell power plants should be possible almost anywhere.

.5 The Japanese are pursuing the development of fuel cells for a number of reasons:

- With few indigenous energy resources, efficient generating devices are being actively pursued.
- High cost of other forms of generation.
- Restricted transmission line access makes fuel cells an attractive option for serving rapidly increasing urban loads.
- Environmental concerns in urban locations (i.e., $NO_x$, $SO_2$ emissions) make low polluting fuel cells even more attractive.
- Fuel cells would be one part of a generation mix that includes nuclear, LNG-fuelled combined cycle and hydraulic plants.
- The Japanese appear to be interested in developing fuel cells not only for their market but also as a power generation device for the world market.

.6 In Europe high energy prices and environmental concerns are renewing interest in the development of fuel cells as a result of their efficiency and low emissions.

.7 In North America increasingly stringent environmental regulations and the relatively high cost of electricity are providing an opportunity for fuel cells to be used in California.

.8 The American Public Power Association has taken an active interest and role in promoting the development of fuel cell technology.

.9 The achievable U.S. market in the 1996 to 2010 time frame is projected to be as high as 30,000 MW based on systems that already own at least some of their own generating capacity, presently face environmental constraints, and have a rate advantage in comparison with their neighbouring power systems. (APPA, 1988; Bergman and Serfass, 1989)

.10 If fuel cell technology is successfully demonstrated and proven to be commercially viable, the main restriction on its potential would be the availability of natural gas.

.11 Current fuel cell costs are high; however, significant cost reductions are forecast as the technology becomes commercial.

.12 A study conducted for the Ontario Ministry of Energy in 1987 indicates that the total cogeneration market within the province of Ontario could be as much as 14,000 MW. Approximately 45 percent, or 6200 MW, of this technical market potential is in the institutional (i.e., universities, hospitals), commercial and residential sectors. The report done for the Ministry of Energy identified fuel cells as a promising technology for this segment of the market. (Ontario Ministry of Energy, 1987)

.13 Since fuel cells are a developing technology, market entry and commercial units will likely not be available until the latter 1990s at the earliest (refer to Figure 3-8-1) and fuel cells will likely not be able to address this market until the year 2000 or later.

### 3-11-3 Projections of Potential

.1 Figure 3-11-1 shows the forecast of potential contribution for fuel cell technology under the three scenarios described in Section 3-11-1.

.2 Addressing the institutional, commercial, residential cogeneration market, and applying the three scenarios described in Part 1, Section 1-8, the following conclusions can be reached about the potential for fuel cells in Ontario.

.3 In Scenario 1 only phosphoric acid fuel cells can be considered to be available. Based on current costs for the technology, it is very unlikely that fuel cell power plants will contribute to the electricity supply mix in Ontario by the year 2005.

.4 In Scenario 2 phosphoric acid and molten carbonate fuel cell power plants may be commercially available. Although cost of electricity is estimated to be higher than from conventional generating options the sale of useable heat may provide a credit sufficient to justify some fuel cell installations. However, very few plants would be built in Ontario by the year 2005 due to the short time between commercial availability and 2005.

.5 In Scenario 3 the potential for fuel cells in the 2005 to 2014 time frame could be significant. Assuming further declines in capital costs approximately 10 to 25 percent of the replacement market for institutional, commercial and residential sectors could become economically viable for fuel cells. This corresponds to a potential of approximately 300 to 800 MW by the year 2014.

*Figure 3-11-1: Forecast of Potential Contribution of Fuel Cell Technology*

| Scenario | Assumptions | Major Factors Affecting Potential | Cost Compared to Conventional Generation | Potential | | Potential Applications |
|---|---|---|---|---|---|---|
| | | | | MW | By Year | |
| 1 | • Current technology (phosphoric acid fuel cells only).<br>• Current costs.<br>• Natural gas as fuel. | • Capital cost<br>• Performance/lifetime of cell stacks<br>• Fuel cost<br>• Use in cogeneration applications | Above | < 1 | 2005 | • Dispersed, small-scale load-displacement/ cogeneration applications. |
| 2 | • New and mature technology (molten carbonate and phosphoric acid fuel cells).<br>• Lower capital costs.<br>• Natural gas fuel. | • As above.<br>• Limited implementation period from time technologies are projected to be "commercially" available. | Equal to or above | < 10 | 2005 | • Dispersed, small-scale load displacement/ cogeneration applications.<br>• Demonstration of dispersed utility applications. |
| 3 | • Mature/commercial fuel cell technologies.<br>• Reduced capital costs.<br>• Natural gas as fuel.<br>• Potential of institutional, commercial and residential cogeneration in Ontario estimated to be ~6200 MW. | • Capital cost.<br>• Fuel cost.<br>• Boiler life of 20 years in ICR market, limits replacement capability.<br>• New technology may be adopted by limited number of customers (10%).<br>• Cogeneration/environmental factors may increase customer acceptance (25%). | Equal to or above | 300 – 800 | 2014 | • Load-displacement/ cogeneration applications.<br>• Limited amount of dispersed utility generation. |

## 3-12 Overall Assessment

.1 Interest in fuel cell power plants results mainly from their ability to use conventional fuels with much higher efficiency than conventional generation technologies, their modularity, and their good environmental performance.

.2 Fuel cells are a rapidly developing technology. Of the three major fuel cell types assessed in this report, only phosphoric acid fuel cells (PAFC) can be considered to be commercially available. Molten carbonate fuel cells (MCFC) are forecast to be commercially available by the period 1995 to 2000 and solid oxide fuel cells after the year 2000.

.3 Current fuel cell costs are high; however, significant cost reductions are forecast as the technology becomes commercial.

.4 This review estimates the current (1991) levelized unit energy cost (LUEC) of electricity produced by PAFC power plants to be in the range of 8.9 to 19.4 ¢/kWh. The projected year 2000 costs for PAFC correspond to a LUEC range of 6.4 to 14.1 ¢/kWh (1991 dollars). The projected year 2000 costs for MCFC and SOFC power plants correspond to LUEC ranges of 5.7 to 12.6 ¢/kWh and 6.1 to 14.6 ¢/kWh, respectively.

.5 These costs indicate that fuel cell power plants are not currently economic for the production of electricity for the bulk electricity system in Ontario if the plants are used for electricity production only.

.6 Fuel cell power plants will most likely first become cost-effective in combined heat and power applications. The sale of useable heat could partially offset electricity production costs for the fuel cell options assessed here, depending on the assumptions made about the value of the heat.

.7 Siting of fuel cell power plants should be possible almost anywhere because of their modularity, quiet operation and low emissions as well as their capability to serve the on-site energy needs of the customer.

.8 Mature fuel cell technology may provide further benefits to utilities. Factory manufactured and assembled packages could reduce power plant lead times; stringent in-plant quality control and testing could improve standardization and reduce construction costs and schedules. Along with modularization, these advantages should enhance planning flexibility for load matching and incremental capacity additions in utility applications while reducing capital exposure. Standardization could enable dramatic reductions in the uncertainties, schedules and costs of environmental regulation and approvals processes.

.9 During the next 10 to 20 years natural gas will likely be the primary fuel of choice for fuel cell operation due to its ready availability, ease of use, and reasonable cost compared to other fuels.

.10 In the longer term gasifiers may also be used to generate syngas from coal to power fuel cells. This development is not expected until molten carbonate and solid oxide fuel cell technologies have reached technical and commercial maturity, likely after the year 2000. Coal gasifiers would be used in combination with large fuel cell power plants in centralized generating facilities.

.11 The solid polymer fuel cell may also be of interest for off-grid applications because of its low temperature operation, its relatively compact and robust design, and the use of an easily transportable liquid fuel such as methanol.

.12 Technical issues that could prevent widespread implementation of fuel cells include less than predicted lifetime of fuel cell stacks (i.e., higher than predicted degradation of performance), and insufficient market development to enable economies of scale to apply to the manufacturing processes to bring the costs down to a point that the technology would be in demand. The operation of demonstration plants including the 200 kW PAFC plants, the 11 MW PAFC plant being operated in Japan and early demonstration units of both MCFC and SOFC technologies will confirm or disprove the performance and potential of this technology.

.13 Currently, cost is an impediment to the widespread implementation of PAFC technology, while MCFC and SOFC technologies are not yet scaled up or proven in sizes of interest to the marketplace. Increasingly stringent environmental regulations are providing an opportunity for the implementation of this clean fossil-fuelled technology in areas such as California. In other jurisdictions such as Japan, where the cost of fuel and electricity is considerably higher than in Ontario, the high efficiency of these devices is an added benefit.

.14 Fuel cells are anticipated to have a higher degree of social acceptance because of the low environmental emissions, limited waste disposal problems, flexibility in use for heat and electricity production, minor siting concerns and minimized requirement for transmission lines.

.15 Use of natural gas as a fuel is well accepted by society. However, some groups may have safety concerns (e.g., related to explosions) about the conversion of natural gas and other fuels to hydrogen within the fuel cell in order to generate electricity.

.16 Fuel cells will create limited employment for tradespeople with skills on par with those required by utilities. With incentives fuel cells will have the potential for creating increased provincial economic development opportunities.

.17 As discussed in Section 3-11, the potential contribution of fuel cell power plants to the electricity supply mix for Ontario could be as low as 1 MW by the year 2005 or as high as 800 MW by the year 2014 depending on costs and technological developments.

.18 The advantages of fuel cell technology include:

- high energy conversion efficiency,
- siting flexibility,
- modularity, and
- low emission levels.

.19 Barriers to large-scale implementation of fuel cell technology include:

- high capital costs, and
- limited experience with the technology.

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### 3-13-1 Additional Reading

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# Part 2: Technology Assessments

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## 4-1 Introduction

.1 The purpose of this chapter is to describe existing and developing biomass-electric technologies and to evaluate their potential for application in Ontario.

.2 The technologies available for the production of energy from biomass are identified in Figure 4-1-1.

.3 The generating technologies emphasized in this chapter are conventional thermal generation processes similar to those used for fossil fuels. Reference is also made to developing and emerging technologies.

.4 The major challenge with respect to the use of biomass lies in the development of cost-effective methods of growing, preparing and handling biomass fuels. Combustion methods must also be developed to convert more of the fuel's chemical energy into electricity.

## 4-2 Fuel/Energy Source

### 4-2-1 General

.1 Biomass is organic matter created by photosynthesis. It is material which is or has recently been plant life. Biomass is a dispersed resource which can be found or grown in large parts of Ontario.

.2 Biomass resources can be used for energy and non-energy purposes.

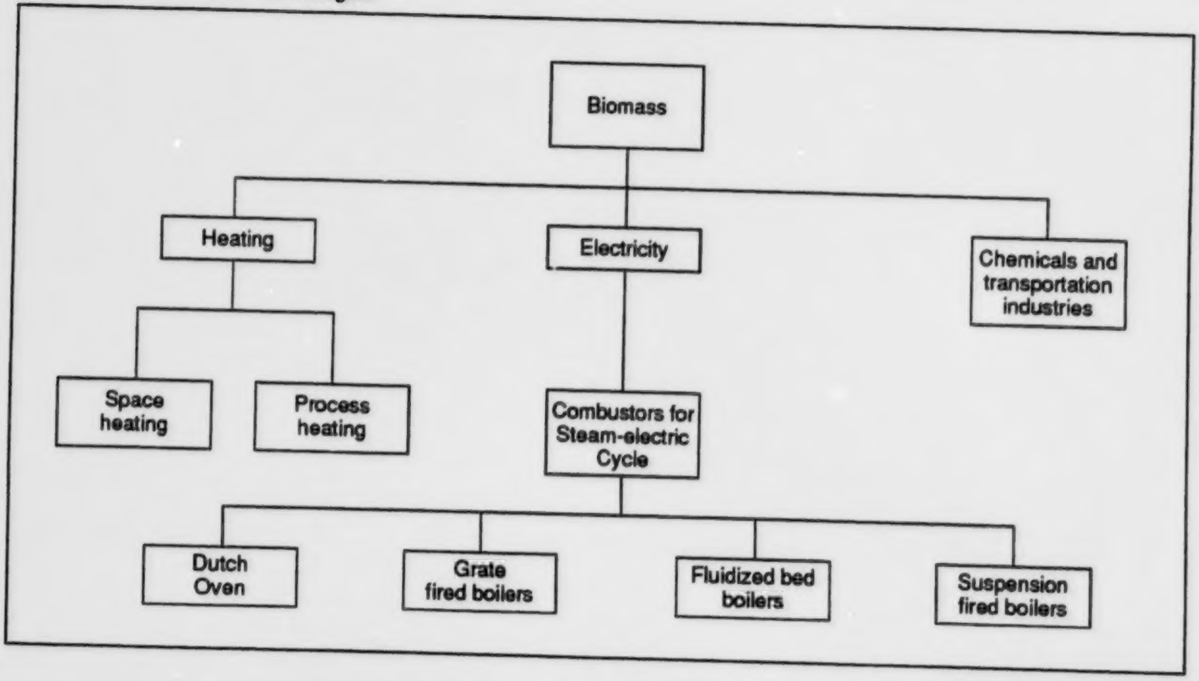
.3 Biomass fuel resources can generally be divided into two major groupings, those which are essentially wastes which can be used as fuel, and those which can be harvested from natural forests or cultivated in plantations for use as fuel.

.4 Examples of waste biomass fuels include wastes from forestry, agriculture and food processing industries. Waste lumber from industrial and construction sites and municipal solid waste comprise other forms of biomass which must otherwise be disposed of. There are also instances in which aquatic plants, grown in inland water bodies for the purpose of absorbing pollutants, have been harvested for testing as biomass fuel.

.5 Biomass wastes found in residential and industrial refuse are discussed in Chapter 6, Municipal Solid Waste.

.6 Agricultural wastes such as straw and cuttings are considerably less dense than wood wastes. Accordingly, they are more difficult and costly to collect and handle. They are not discussed extensively in this report.

*Figure 4-1-1: Biomass Technologies*



.7 In some countries biogas derived from animal manure is used to provide light and heat; however, the gas is not a significant source of electricity.

.8 Food processing wastes contain high moisture levels and are therefore difficult and costly to prepare for energy production.

.9 Ontario's forests are a potential source of biomass fuel. Figure 4-2-1 shows that approximately 68,000 hectares of natural forest clear cutting would be required to produce wood fuel for sustained operation of 15 MW of electrical generation. There are, however, environmental and ecological drawbacks to clear cutting of natural forests.

.10 Accordingly the clear cutting of natural forests is not considered to be an environmentally acceptable source of biomass for energy production; however, if natural forest biomass were to be made available by an acceptable process of selective thinning it could be utilized as fuel for the technologies described in this chapter.

.11 Logging residues and wood processing wastes are included among the biomass fuels dealt with in this chapter.

.12 Figure 4-2-1 illustrates that biomass fuels cultivated expressly for the purpose of energy production can be grown on plantations where production can be maximized under controlled conditions.

.13 Logging residues and wood processing wastes are most prevalent in northern Ontario, whereas Ontario's only biomass plantation (supplying biomass for paper production) is in the eastern part of the province, an area which might support other plantations.

.14 In this report discussion of plantation biomass focuses on hybrid poplar and willow. These are fast-growing species and research continues to develop other high yield hybrids.

.15 Plantation biomass could be produced in areas where trees are specifically planted for fuel wood. These areas can use either the coppice concept, where trees are regularly cut back and allowed to resprout, or the single stem concept, involving high density planting and harvesting of the crop at about 10 year intervals. The most promising coppice plantation species is willow. Single stem plantations use poplar or birch.

.16 Figure 4-2-1 illustrates that three year mini-rotation hybrid willow and poplar plantations involve the use of 6400 to 6900 hectares of land, respectively, dedicated to fuel production for 15 MW of generation. Short-rotation hybrid plantations, on the other hand, have been tested (10 years) and would require about 24,000 hectares to fuel the same amount of electrical generation.

***Figure 4-2-1: Forest and Plantation Areas Required for Electrical Generation (1)***
***[Source: Monenco, 1990]***

| | Rotation Period Years | Yield Oven-Dried Tonnes Per Hectare | Net Area Requirement (Hectares) |
|---|---|---|---|
| Natural Forest Selective Thinning | 10 | 50 | 17,000 (2) |
| Natural Forest Clear Cutting (3) | 80-year regrowth | 100 | 68,000 |
| Short-Rotation Hybrid Poplar Plantation | 10 | 35 | 24,000 |
| Mini-Rotation Hybrid Poplar Plantation | 3 | 37 | 6,900 |
| Mini-Rotation Hybrid Willow Plantation | 3 | 40 | 6,400 |

**Notes:** (1) 85,000 oven-dried tonnes of wood fuel per annum required for 15 MW of electrical generation capacity.
(2) 85,000 ÷ 50 x 10 = 17,000
(3) Clear cutting should be considered only as a preliminary step towards establishing an energy plantation.

## 4-2-2 Properties of Biomass

.1 Figure 4-2-2 compares the properties of wood with other fuels. That table illustrates that wood's heating value is lower than that of heavy fuel oil or bituminous coal, but similar to that of lignite and peat.

.2 Wood should typically have an average moisture content not exceeding 50 percent to burn in a steam generating furnace. Wood fuel dried to 35 percent moisture content provides better combustion efficiency than wood fuel at 50 percent moisture content. Although combustion efficiency improves with dryness, fire hazards also increases in proportion to dryness.

.3 Figure 4-2-3 identifies the heating value of wood at various moisture content levels. The heating value of wood of different species varies relatively little, and is typically about, 20.0 MJ/kg oven-dried.

.4 Figure 4-2-3 illustrates that green wood at 50 percent moisture content contains about one half the heating value of oven-dried wood (near zero percent moisture content).

.5 Plantation grown biomass can be fairly uniform in terms of its physical and chemical properties. Wood fuel from plantations can be prepared to specifications which suit the combustion technology at the generating station.

.6 While the chemical properties of logging residues and wood processing wastes are also fairly consistent, the physical and fuel properties of those fuels can vary considerably depending largely upon particle size distribution, moisture content and the presence of extraneous material.

*Figure 4-2-2: Comparison of Biomass to Other Fuels [Source: Monenco, 1990]*

| | Heavy Fuel Oil | Coal (Bituminous) | Lignite | Peat | Wood |
|---|---|---|---|---|---|
| C % | 83-86 | 76-87 | 65-75 | 50-60 | 48-50 |
| H % | 11.5-12.5 | 3.5-5.0 | 4.5-5.5 | 5.0-6.5 | 6.0-6.5 |
| O % | 1.5-2.5 | 2.8-11.3 | 20-30 | 30-40 | 38-42 |
| N % | 0.2-0.3 | 0.8-1.2 | 1-2 | 1.0-2.5 | 0.5-2.3 |
| S % | 2.0-2.8 | 1.0-3.0 | 1-3 | 0.1-0.2 | <0.1 |
| Ash Content % | 0.3 | 4-10 | 6-10 | 2-10 | 0.4-0.6 |
| Melting Point of Ash % | | 1100-1300 | 1100-1300 | 1100-1200 | 1350-1450 |
| Volatiles % | | 10-50 | 50-60 | 60-70 | 75-85 |
| Bulk Density kg/m$^3$ | 920-970 | 720-880 | 650-780 | 100-400 | 320-420 |
| Effective Heat Value of Dry Matter MJ/kg | 41.4-42.0 | 28.4-33.0 | 20.0-24.2 | 17.5-21.3 | 18.4-21.0 |
| Operational Moisture % | 0.1 | 3-8 | 40-60 | 40-60 | 30-60 |
| Effective Heat Value at the Lowest Operational Moisture Content, MJ/kg | | 27.5-32.0 | 12.0-14.5 | 10.5-12.6 | 12.9-14.7 |
| Effective Heat Value at the Highest Operational Moisture Content, MJ/kg | | 26.1-30.4 | 8.0-9.7 | 7.0-8.5 | 7.4-8.4 |

*Figure 4-2-3: Heating Value of Wood at Various Moisture Contents [after Pfeiffer, 1990]*

| Moisture Content (%) | Heating Value (MJ/Tonne) |
|---|---|
| 0 | 19,800 |
| 10 | 17,840 |
| 20 | 15,840 |
| 25 | 14,850 |
| 30 | 13,860 |
| 35 | 12,870 |
| 40 | 11,880 |
| 45 | 10,890 |
| 50 | 9,900 |
| 60 | 7,920 |
| 70 | 5,940 |
| 80 | 3,960 |
| 90 | 1,980 |

Green wood of 50% moisture produces about one half the energy of oven dry wood (0% moisture). Therefore, it is always preferable to have the driest wood possible for combustion purposes as oven air dried wood (with 10% moisture) has almost twice the calorific value of green wood.

### 4-2-3 Biomass Fuel Forms

.1 Biomass can take the form of solid, liquid and gaseous fuels.

.2 There are several processes (e.g., crushing, fermentation, fast pyrolysis and, indirect hydrogeneration) by which biomass can be converted into liquid fuels (including methanol and ethanol) which, because of their high value may be better used as petroleum substitutes in the transportation and chemical industries. The lignin residue from ethanol production may be used for electricity generation.

.3 Similarly, there are several processes (aerobic and anaerobic digestion, pyrolytic gasification) by which biomass can be converted into biogas having low-to-medium energy content; however, those processes are still under development.

.4 Biomass can also be made into dense fuels in the form of pellets, briquettes, and logs; however, these products have so far proved too expensive for large scale energy production.

.5 Typical wood chip fuel specifications establish maximum concentrations of ash plus dirt, maximum particle size and fines limits, maximum moisture content (usually 50 percent on average) and average higher heating value.

.6 Logging residues and timber industry wastes are less uniform in terms of size and moisture content; however, the energy content of such wood waste is approximately the same as that of plantation grown wood.

.7 Utility fuel specifications place restrictions on the size distribution of the material.

### 4-2-4 Biomass Production and Processing

.1 This section deals primarily with two methods of producing plantation biomass – short-rotation and mini-rotation hybrid willow and poplar species.

.2 In either case monoculture must be avoided (i.e., multi-clonal hybrids must be planted) to guard against catastrophic crop losses caused by disease or pests.

.3 Energy plantations will vary in size depending upon:

- terrain (hilly or flat),
- physical layout of the land (parcel sizes, degree of contiguity), and
- location (proximity to urban areas and transportation, and geo-political barriers).

.4 Other factors involved in the production of plantation biomass include:

- soil conditions,
- climate,
- type of species/hybrid,
- nutrition,
- pest/disease control,
- environmental compliance, and
- the economics of producing an end product with the desired specifications.

.5 Nominal harvesting intervals are used in this report; however, there are a number of technical and economic criteria which determine actual harvesting intervals.

.6 Large centralized plantations may be managed by a single organization or they may be decentralized and managed by local farmers who grow biomass fuels as part of their broader crop mix.

.7 In either case biomass plantations would be managed as continuous wood production systems by one or more farmers or foresters who would maintain an intimate knowledge of the progress of each tract.

.8 In order to bring unused land into a productive state site preparation may include heavy clearing, stone removal, fence removal, drainage, levelling and road access improvement (construction of culverts and lanes).

.9 Abandoned or marginal agricultural land has typically been used for experimental plantations since land and site preparation costs are minimized. These conditions may not suite large scale energy plantations.

.10 Figure 4-2-4 illustrates a conceptual centralized plantation management unit (PMU) suited to either short or mini-rotation management. The total size of the PMU is approximately 10,000 hectares (100 km$^2$) which makes allowance for non-productive land in the area. In practice, several PMUs might be required to serve a station, depending upon their productivity and the size of the station. Using three-year mini-rotation such a PMU could supply fuel to a 15 MW station.

.11 If the total land area of eastern Ontario (approximately 2.8 million ha) could be utilized for biomass plantations, the area would support approximately 235 PMUs. Depending upon the rotation and species the area could provide fuel for 1500 MW to 7200 MW of electrical generation.

.12 The PMU or group of PMUs comprising the energy plantation should be close to a major transportation artery (preferably rail because of the large volumes of the material being transported) over which harvested material would be hauled to the generating station.

.13 Eastern Ontario is considered to be suited to plantation growth because it has abundant tree growth and a considerable amount of land is devoted to forest and/or marginal agricultural enterprises.

### *Short-rotation Plantations*

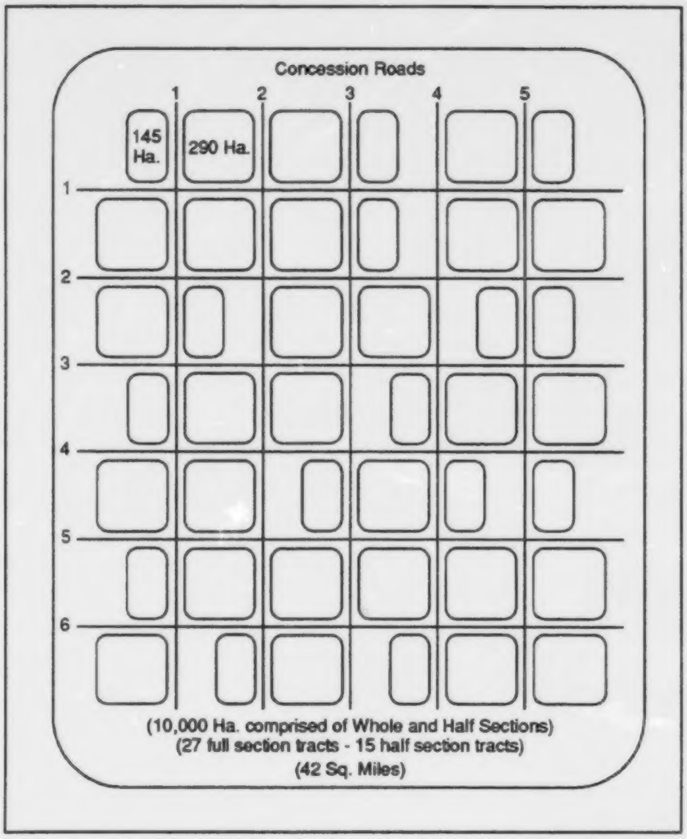
.14 In short-rotation poplar plantations tree density would be about 1,100 trees per hectare.

.15 Trees would be allowed to grow for not less than five and preferably 10 or more years before being harvested. Trees from such plantations would be harvested using standard forestry equipment and techniques.

.16 Feller-bunchers equipped with accumulator shear heads could be used to fell trees and place them in bunches for skidding. Grapple skidders would transport the bundles to a central location where the trees would be chain-flailed prior to chipping. Where possible, rail cars would be used to transport wood chips to the generating station. Alternatively the wood chips would be blown into vans for transport over established roadways to the generating station site.

.17 A set of the equipment described above would be capable of clear cutting 2.5 hectares per day. A normal working year in eastern Ontario, for instance, amounts to about 180 days during which the equipment can work on the land. Therefore one set of equipment could clear about 450 hectares annually.

*Figure 4-2-4: Conceptual Plantation Management Unit [Pfeiffer and Cozzarin, 1990]*


Concession Roads
1
2
3
4
5
145 Ha.
290 Ha.
1
2
3
4
5
6
(10,000 Ha. comprised of Whole and Half Sections)
(27 full section tracts - 15 half section tracts)
(42 Sq. Miles)

.18 Trees cut in the fall have a moisture content of about 50 percent. They would be left to dry over the winter before they were chipped and hauled away in the spring by which time their moisture content would have decreased considerably. A further advantage of winter harvesting is that the stems are devoid of leaves, which is good for combustion, and the fallen leaves return some nutrients to the soil.

.19 Coppicing systems allow new stems to grow on the same root stock several times before a complete replanting is required.

### *Mini-rotation Plantation*

.20 Approximately 30,000 to 32,000 cuttings per hectare (approximately 20 cm long) would be planted at corn-like spacings in freshly turned soil. Planting would take place in early April and could be accomplished with a six row (six person) riding planter and nursery-grown planting stock.

.21 The plantation management unit could be the same as that illustrated in Figure 4-2-4, but since the methods by which these plantations are established and managed are more akin to agricultural practices than forestry it is possible that local farmers could devote some portions of their land to biomass production.

.22 The young trees would be cultivated and harvested in ways analogous to those for corn silage. Using the coppice method the sprouting trees are cut near the ground while leaving the lowest portion of the growth to sprout again.

.23 Figure 4-2-5 is a graphic depiction of the site preparation, planting and harvesting cycle involved in the mini-rotation biomass plantation concept.

.24 Willow harvesting takes place approximately every three years. After about three years some species require the use of heavier forestry harvesting equipment and a scaled down felling, bunching, skidding and chipping operation. Poplar harvesting requires a somewhat longer rotation because of its slower growth rate.

.25 There are again a number of factors which determine the actual rotation cycle for a given PMU including growth patterns of the species-spacing-culture combination, product values and management costs.

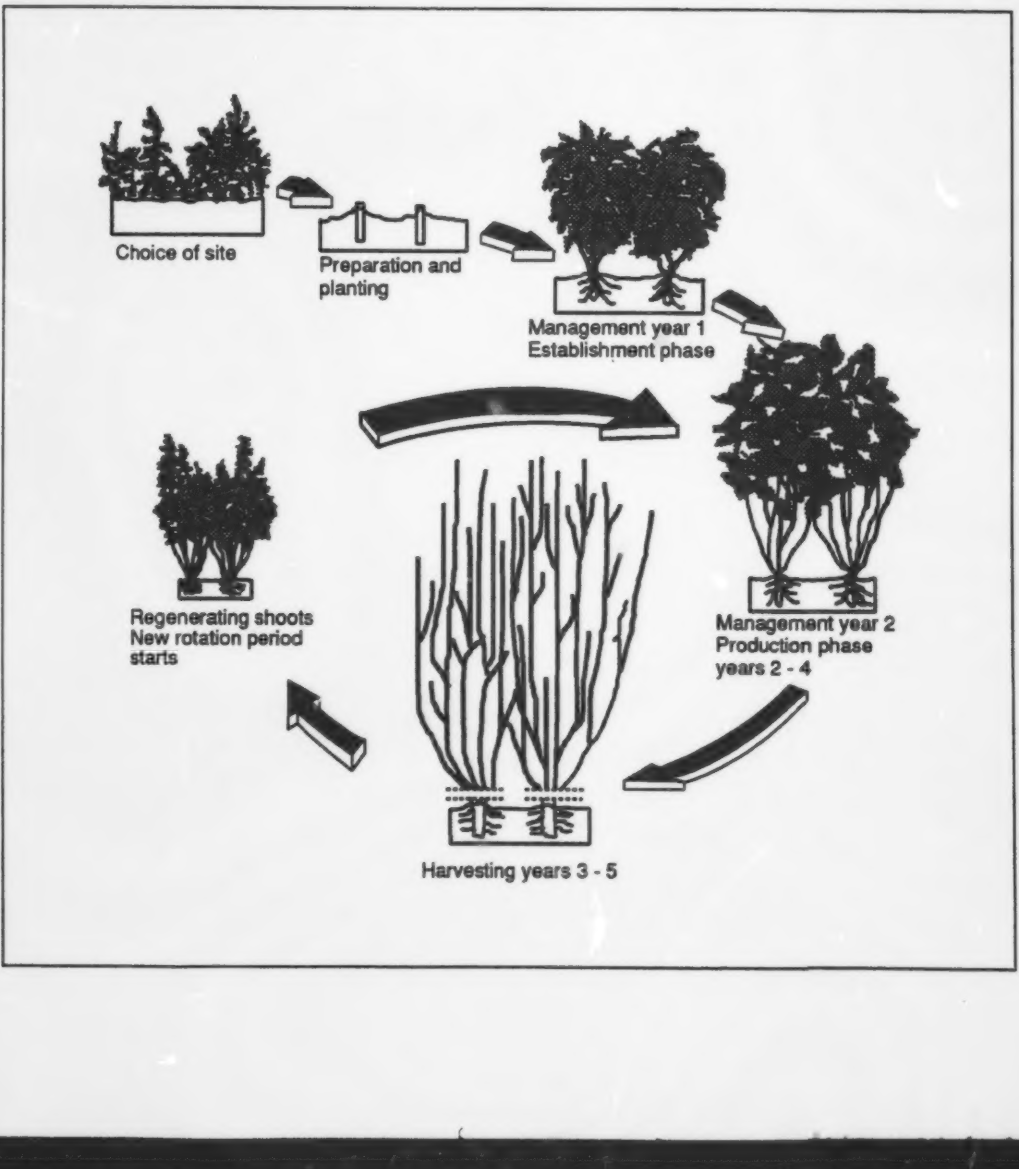
.26 In some situations it is possible that willow could be harvested annually for several years and then there could be a four to 10 year interval before a final crop was taken. Willow species could grow to a height of about one meter in the first year, and could be approximately three meters tall at three years.

.27 According to some estimates a plantation might be cultivated for 20 to 30 years before replanting became necessary.

.28 Plantation grown willow is expected to be mechanically harvested in winter and the stalks stacked for about six months to dry from the green condition of 50 to 60 percent moisture content to about 25 to 35 percent moisture content.

.29 The stalks may be transported to the generating station for fuel processing or they may be chipped using conventional forestry equipment prior to transportation.

***Figure 4-2-5: Plantation Biomass Mini-Rotation Concept [Source: E. Sennerby-Forsse]***


Choice of site
Preparation and planting
Management year 1
Establishment phase
Management year 2
Production phase
years 2 - 4
Harvesting years 3 - 5
Regenerating shoots
New rotation period
starts

## 4-3 Technology Description

.1 Conventional generation and environmental control concepts are discussed generally in Appendix B.

.2 Biomass-fired generating stations are basically "mine-mouth" power plants because biomass requires large land areas on which to accumulate the resource and because the fuel typically has a high moisture content (in the 50 percent range), low bulk density (around 300 kg/m$^3$) and low energy density (around 10 gigajoules/green tonne). The fuel thus cannot economically be transported over long distances.

.3 A "wood power complex" could include a centrally located wood processing facility, the generating station, the energy plantation and the storage/transportation system illustrated in Figure 4-3-1.

.4 Stations fuelled with wood waste have often been located near large pulp and paper or wood processing mills where relatively large quantities of wood waste are easily accumulated.

.5 Figure 4-3-2 compares the five "conventional" technologies which have been used or are currently used to convert the chemical energy of biomass into steam energy:

- dutch oven,
- spreader stoker pinhole grate,
- spreader stoker travelling grate,
- gravity feed inclined grate, and
- fluidized beds.

.6 The conventional technologies are currently used to burn waste biomass; however, plantation-grown biomass may be better suited to more advanced and more efficient combustion technologies which are under development.

.7 Existing biomass fuelled plants convert about 25 percent of the fuel's chemical energy into electrical energy.

.8 Increased fuel efficiency can be obtained from all electrical generation technologies by utilizing waste heat for district or process heating.

### 4-3-1 Generating Equipment

.1 This section describes fuel preparation and handling systems and generating plant that would be designed to generate electricity from wood fuel in several of its solid forms.

.2 The boilers and turbines used to derive electricity from biomass are very much the same as those described and illustrated in Appendix B.

.3 Biomass fuel handling and preparation systems are substantially different from those used in coal-fired plants and vary with the type of biomass being used.

.4 The relatively low energy content and high moisture content of biomass require that wood-fired boilers and fuel handling systems be much larger than those for coal or oil-fired units producing the same power output.

.5 Biomass-fired boilers have, until recently, employed grate systems to achieve complete combustion. Fluidized bed boilers are currently considered to be a better means of reducing $NO_x$ emissions when burning biomass.

.6 Conventional biomass-fired units can be designed to be co-fired with other fuels. Changes in fuel can result in significantly different energy unit outputs and emissions.

.7 Biomass fired boilers require relatively little ash handling since wood has a lower ash content than, for example, coal as shown earlier in Figure 4-2-2.

.8 Particulate emissions are controlled by devices such as electrostatic precipitators, multicyclones, scrubbers and fabric filter baghouses. These systems are discussed in Appendix B.

.9 $SO_2$ emissions from biomass-fired generating stations are low, as biomass fuels typically contain negligible sulphur as shown in Figure 4-2-2. Therefore, it is unlikely that flue gas desulphurization systems would be required for biomass-fuelled power plants.

.10 Biomass-fired systems can comply with $NO_x$ emission regulations either through initial design or retrofit.

*Figure 4-3-1: A Wood Power Complex*
*[Pfeiffer and Cozzarin, 1990]*

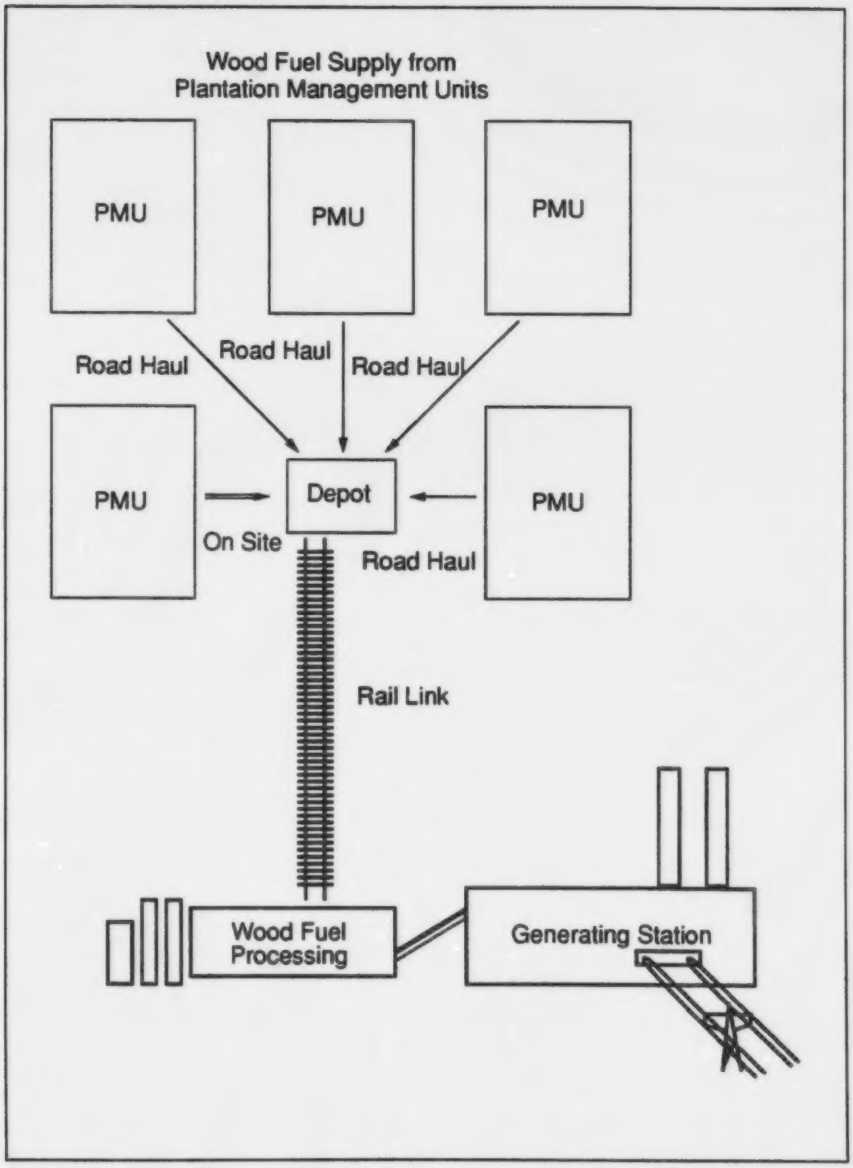

Wood Fuel Supply from
Plantation Management Units
PMU
PMU
PMU
Road Haul
Road Haul
Road Haul
PMU
Depot
PMU
On Site
Road Haul
Rail Link
Wood Fuel Processing
Generating Station

*Figure 4-3-2: Comparison of Wood-Burning Furnaces [Monenco, 1990]*

| | A<br>Dutch Oven | B<br>Spreader Stoker Pinhole Grate | C<br>Spreader Stoker Travelling Grate | D<br>Gravity Feed Inclined Grate | E<br>Fluidized Bed |
|---|---|---|---|---|---|
| Acceptable Max. Moisture Content in Wood Fuel | High<br>65% | High<br>65% | Medium<br>55% | High<br>65% | High<br>65% |
| Thermal Inertia | High | High | Low | Medium | High |
| Suitable Wood Fuel | Unprepared Fuel With Limited Max. Size | Hogged Fuel | Hogged Fuel | Partially Hogged Fuel | Unprepared Fuel With Limited Max. Size |
| Max. Steam Output Rating | Medium | High | High | Medium | Medium |
| Ash Entrainment | Low | Low | High | Medium | High |
| Fuel Bed | Stationary | Stationary | Moving | Moving | Moving |

### 4-3-2 Fuel Handling and Preparation: Short-rotation Plantation

.1 When whole tree wood chips were delivered to a generating site they would typically have a moisture content of 50 percent.

.2 The generating station would have its own storage space and equipment for receiving, storing, preparing and feeding the fuel to its boilers.

.3 Systems can be designed to divert hot flue gases to dry the wood just before it enters the feed system to the combustion chamber, thereby improving unit efficiency.

### 4-3-3 Fuel Handling and Preparation: Mini-rotation Plantation

.1 Harvested wood biomass must be carefully stored in order to permit effective drying and to avoid energy losses and fungus growth.

.2 Wood harvested in late autumn or winter has a moisture content of about 50 percent, an amount which will decrease to about 25 percent if the stalks are piled for about six months. Care is necessary since drying in storage increases fire hazard.

.3 On the other hand, freshly harvested wood stored in chipped condition will lose considerable energy through degradation and risk the growth of fungi.

### 4-3-4 Fuel Handling and Preparation: Waste Wood Biomass

.1 Waste wood biomass is generated at pulp and paper mills, sawmills and plywood mills. The waste is generally in the form of bark, slabs, cuttings and sawdust which would otherwise be burned or landfilled.

.2 Where necessary the waste may be hogged to achieve a consistent size suited to the combustor.

.3 The fuel may be contaminated with dirt, foreign objects and logs which tend to complicate fuel handling and increase wear on equipment. The variability in the fuel dictates the amount of processing required and/or the type of combustor that can be employed with the fuel.

.4 The fuel handling technology employed is sometimes similar to that used to burn municipal solid waste (refer to Chapter 6). Front end loaders pile the waste and grapple cranes lift the fuel into a hopper. Hydraulic rams at the base of the hopper force the fuel onto the combustion floor or grate. More sophisticated and automated systems are also marketed.

.5 The combustion systems currently used to convert wood waste fuels to electricity include inclined grate, travelling grate, and fluidized beds.

## 4-4 Experience

### 4-4-1 World Experience

.1 Wood biomass is still a primary fuel in developing countries, but not for the generation of electricity.

.2 Large proportions of total energy consumption in developing countries (mainly for heating and cooking) are derived from wood, which is the world's fourth largest source of energy, approximately the same as natural gas. Examples of wood energy as proportions of total annual energy are: Latin America 30 percent, Asia 42 percent, Africa 76 percent. The contribution of wood waste biomass to total world energy consumption is reported to be 7.5 percent.

.3 Worldwide, the pulp and paper and other industries have utilized biomass waste to cogenerate electric power while providing process heat.

.4 The oil crisis in the 1970s provided an incentive for utilizing the wood waste produced by the wood processing industry for electrical generation.

.5 Biomass-fired thermal generating plants exist in the U.S., Sweden, U.K., Canada and in other countries.

.6 Scandinavian countries have large forest industries and their waste biomass is used for cogeneration of electricity and steam for process or district heating.

.7 In 1989, wood fuels supplied about one percent to the energy required in Sweden for electricity generation and district heating. Sweden plans to generate significantly more electric power from biomass fuel in the next century.

.8 The use of biomass for electricity generation in the U.S. has grown from 50 MW installed capacity in 1978 to 8500 MW in 1990. American experience has shown that biomass is a limited resource. There are reports of fuel shortages at existing stations.

.9 Some of the biomass-fuelled plants in California and Vermont generate peaking power when fuel shortages are experienced and the cost of fuel is too high to justify base load operation.

### 4-4-2 Canadian Experience

.1 Industries such as the pulp and paper, timber and wood working industries, utilize the energy content of the waste wood in much the same way as their equivalents in other countries for generation of electrical energy and/or for space and process heating.

.2 There is considerable activity in British Columbia towards utilizing biomass waste for electrical generation and cogeneration.

.3 B.C. Hydro estimates that approximately 450 to 500 MW are in place in the timber and pulp and paper industries supplying in-house electricity and heat loads. However, it is believed that most of this is fired by black liquor rather than wood waste.

.4 The Ministry of Energy, Mines and Petroleum Resources in Victoria has recorded that 26 million cubic meters of wood waste was produced in B.C. in 1988. Of this amount 25 million cubic meters were incinerated in beehive burners (without generation of energy) and the balance was landfilled. Action is now planned to better utilize this resource.

.5 Plans exist in B.C. for wood/gas fired electrical cogeneration at the following locations; some of this capacity is already under construction:

- North West Energy Corporation: Williams Lake project, 60 MW from wood waste, in-service 1993.
- Howe Sound Pulp and Paper: Port Melon B.C., 105 MW from black liquor and wood waste. Of the total of 105 MW, 50 MW will be fuelled by wood waste.
- Celgar Pulp Company in Castlegar, B.C., plan wood-fuelled generation of about 2.5 MW from solid biomass waste.

### 4-4-3 Ontario Experience

.1 Industries in Ontario, particulary pulp and paper, timber and wood working industries, fire wood waste for generation of process steam and some use their in-house waste for cogeneration.

.2 Figure 4-4-1 lists biomass-fired load displacement plants which have been in operation in the province of Ontario for some time. The plants burn waste wood in combination with other fuels.

.3 A number of non-utility cogeneration projects that sell electricity to Ontario Hydro are in operation or are under construction in Ontario. They burn either wood or wood in combination with natural gas and include the following:

- A wood-fired project in Chapleau produces 7 MW of electrical generation firing wood waste.
- A 12.5 MW wood waste and natural gas facility is in operation at Smooth Rock Falls.
- A 33 MW wood and natural gas cogeneration plant has been commissioned in Cochrane. It produces 10 MW from wood waste.
- A 90 MW plant operated by Boise-Cascade and located in Fort Frances uses black liquor as the fuel.
- A 102 MW wood and natural gas cogeneration plant was recently commissioned in Kirkland Lake. It produces about 17 MW from wood waste.

.4 The Ontario Ministry of Energy and Ontario Hydro have also carried out test burns to determine the feasibility of co-firing grain waste in a lignite-fired boiler at Thunder Bay Generating Station. The findings were technically favourable, apart from increased $NO_x$ production of about 9 percent. This was partly due to the fact that the grain wastes have higher nitrogen content than lignite.

.5 There are no generating stations in Ontario fired primarily by plantation-grown biomass. However, the University of Toronto has embarked on a program to cultivate species from which stock for large scale plantations may be drawn.

*Figure 4-4-1: In-Service Load Displacement Plants Utilizing Wood Waste*

| | Industry | Capacity (MW) |
|---|---|---|
| C.P. Forest Products – Thunder Bay | Pulp & Paper | 69.4 |
| James River – Marathon | Pulp & Paper | 15.5 |
| Malette Kraft – Smooth Rock Falls | Pulp & Paper | 15.0 |
| Spruce Falls P&P – Kapuskasing | Pulp & Paper | 21.5 |
| Weldwood – Searchmont | Pulp & Paper | 0.75 |
| C.P. Forest Products – Dryden | Pulp & Paper | 37.0 |
| E.B. Eddy – Espanola | Pulp & Paper | 24.0 |

## 4-5 Potential System Application

.1 Biomass plants are dispatchable and could be operated to meet base or intermediate loads.

.2 For economic and technical reasons (frequent start-ups and shutdowns would be undesirable), biomass plants should be base-loaded.

.3 For economic reasons, biomass plants are best located near the source of fuel (whether wood waste or plantation biomass). This factor and the ability of the local grid to accept power could potentially limit the size of the plant.

## 4-6 Environmental Considerations

.1 This section discusses environmental considerations, both natural and social, associated with the combustion of wood waste and with the cultivation and burning of plantation-grown biomass consisting of fast-growing softwoods such as hybrids of willow and poplar.

### 4-6-1 Natural Environment

.1 This section discusses environmental and safety issues associated with biomass technologies and their impact on the natural environment, under the headings of air, land, water and other.

.2 Wood-fired power plants may produce:

- fugitive dust emissions,
- odours and leachates from fuel storage piles,
- oxides of sulphur ($SO_x$),
- oxides of nitrogen ($NO_x$),
- trace organics,
- carbon dioxide ($CO_2$),
- carbon monoxide (CO), and
- bottom ash and fly ash.

.3 Pollution control technologies used at coal-fired generating stations are applicable to wood-fired generation.

*Air*

.4 Carbon dioxide emission is common to all conventional thermal power generation. There is no commercially available method for removing $CO_2$ emissions from flue gas. Due to the absorption of $CO_2$ by growing trees, properly managed biomass plantations would be $CO_2$ neutral except to the extent that fossil fuels would be burned to cultivate and transport wood.

.5 Wood contains low concentrations of sulphur (in the order of .05 percent by weight) and when burned produces much lower $SO_x$ emissions per kWh than coal or oil (SESEE, 1991).

.6 $NO_x$ emissions from the combustion of wood are comparable to or somewhat higher than those from fossil fuels per unit of electricity generated. Fluidized bed combustion possibly supplemented by specialized systems can be used to reduce $NO_x$ emissions. $NO_x$ emissions can be controlled as needed to satisfy federal guidelines and provincial regulations.

.7 Particulates emissions from the combustion of wood can be controlled using existing technology, as discussed in Appendix B.

.8 Unburned hydrocarbons, for example, volatile organic compounds (VOCs) and polycyclic aromatic hydrocarbons (PAHs) and carbon monoxide emissions resulting from incomplete combustion, can be controlled by boiler design and operation.

.9 Vehicular activities associated with plantations would result in emissions of $NO_x$, $CO_2$, CO, $SO_2$, VOC and particulates.

.10 Dust emissions from fuel piles and fuel and ash handling systems are expected to be controlled by covering or spraying.

.11 Fuel pile odours can be controlled by periodically turning the pile to prevent anaerobic decomposition.

*Land*

.12 The effect on ecosystems hosting new plantations would be directly related to the previous use of the land.

.13 Plantations would require the application of fertilizers to offset the loss of nutrients and organic matter.

.14 Plantation activities have the potential to result in soil disturbance, compaction, and erosion.

.15 Pesticides and herbicides may be required to manage infestation and weed control.

.16 Plantation lands could be used for agriculture on retirement of the generating station.

.17 A biomass-fired generating station of 75 MW would occupy approximately 35 to 50 hectares and require a plantation area of about 50,000 hectares assuming the use of mini-rotation hybrid willow plantations and operation at about 80 percent ACF.

.18 Typically biomass combustion will generate less ash than will coal for an equivalent amount of electrical generation.

.19 Wood ash can be returned to the plantation unit to be spread as low grade fertilizer and mineral source.

***Water***

.20 Irrigation could be considered for some sites to optimize plantation crop growth.

.21 Wood pile leachates must be managed and in-plant wastes such as chemicals and lubricants must be disposed of according to existing regulations.

.22 Cooling water requirements for biomass plants would be comparable to or somewhat higher than fossil-fuelled stations per unit of electricity. Where once through cooling is not practical, wet or dry air cooling is an alternative.

.23 Stations providing district or process heating make better use of the energy content of the fuel, and less heat is discharged to cooling systems.

***Other***

.24 While biomass can be considered a renewable resource it is not currently known how long a plantation can be sustained at a given location. Present projections are that short rotation hybrid poplar may have to be replanted after about 40 years, following four harvests. Mini-rotation poplar and willow may have to be replanted after nine to twelve years, following three to four harvests.

.25 Noise emissions from a biomass-fired generating station would be comparable to those from a coal-fired facility.

.26 Biomass fuel piles must be managed and monitored to prevent the occurrence of spontaneous combustion or the production of objectionable odours.

### 4-6-2 Social Environment

.1 This section discusses issues associated with biomass technologies and their impact on the social environment, under the headings of socio-economic effects and societal considerations.

***Socio-Economic Effects***

.2 Because farming and forestry activities in the Province are highly mechanized, it is not anticipated that biomass operations will provide additional regional employment benefits.

.3 Biomass-fuelled generating facilities might provide local employment benefits and economic stimulus. These benefits could be significant for smaller northern or eastern Ontario communities.

.4 Generating facilities using short or mini-rotation plantations might provide local economic stimuli in areas of marginal agricultural potential.

.5 Generating facilities using short-rotation plantations might also provide local economic stimulus in the forest industry.

.6 Utilization of wood waste could make host industries more competitive if energy savings were realized through biomass-fuelled cogeneration facilities.

.7 The potential exists for localized community impacts (e.g., increased traffic) during fuel extraction, processing, construction and operations activities. Depending on the community, these impacts may be similar to those related to current forestry practices. Undesirable impacts could be adequately addressed through mitigation measures.

.8 Workforce effects (such as the immigration of workers and families with different or expanded requirements for schools, recreation facilities and municipal services) are expected to be minimal as biomass operations may be located in regions with an existing skilled labour force (woodworkers, skidder operators, etc.).

### *Societal Considerations*

.9 Familiarity with the concept of burning wood to produce heat (i.e., fireplaces, wood stoves) enhances the social acceptability of technologies that burn wood to produce electricity. As biomass wastes are largely recyclable and residual wastes are minor, this technology offers potential to reduce the social impacts associated with waste disposal and increase its overall social acceptability.

.10 Changes in current institutions and practices within Ontario's forestry and agriculture sectors would be required to support the adoption of biomass waste gathering processes, sustained yield forests and sustainable plantations and/or agricultural activities. With the exception of forestry activities and practices of Conservation Authorities and Regional Forests, comparatively little in the way of sustained yield forestry activity occurs in Ontario today.

.11 Social concerns about the protection of the environment may arise should biomass plantations result in excessive land consumption, ecosystem disruption as part of the clearing process, chemical processes or other characteristics of the growing, harvesting and processing cycle.

## 4-7 Operational Considerations

### 4-7-1 Maintenance

.1 A biomass plant would likely be shut down for a period of two to four weeks each year, probably in summer, for annual off-line maintenance. Maintenance inspection or repair, which can only be done during downtime would be carried out during this annual shutdown. Major overhauls would likely be scheduled every five to seven years and take two to three months.

### 4-7-2 Staffing

.1 A biomass-fired plant would require staff similar in number and qualifications to those employed at conventional fossil-fuelled plants of the same size.

### 4-7-3 System Life

.1 Biomass plants are assumed to have a 30 year life given adequate maintenance, interim repair, replacement and major overhauls.

## 4-8 Development Issues

.1 Conventional biomass electricity generation technologies are proven, and more efficient and advanced technologies are under development.

.2 Waste biomass is a limited resource. For this reason, significant development effort needs to be devoted to growth of plantation biomass and to selective thinning technology for natural forests.

.3 Uniform fuel is generally required to permit the use of more efficient and advanced technologies. Uniform fuel is more easily produced from plantation biomass than from waste biomass. A major development issue, therefore, is the development of cost-effective processes to obtain uniform fuel from plantation biomass. A variety of initiatives are underway, most of which are focused on increasing the yield from biomass plantations.

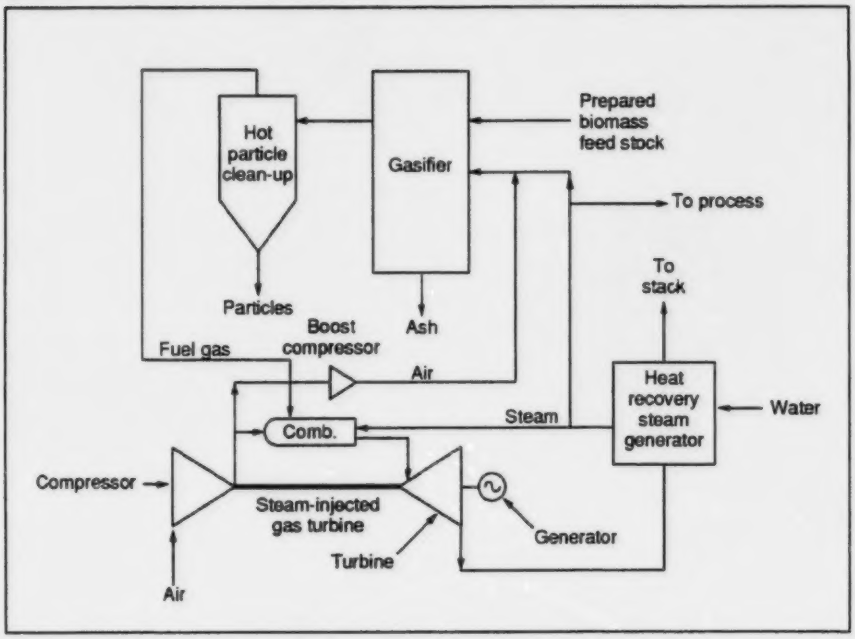
.4 Several companies have developed processes to dry and pulverize biomass fuels for efficient combustion in suspension-fired boilers. The technology is available now but will become more marketable when it can be applied to "specification biomass fuel" such as may be derived in the future from plantations.

.5 Other initiatives are underway to improve fuel combustion efficiencies from the current 25 percent level to the order of 40 percent. Those initiatives involve the gasification of biomass using Integrated Gasification Combined Cycle systems (Biomass IGCC) and include:

- BIG/STIG (Biomass Integrated Gasification/Steam Injected Gas Turbine), a process under development by Princeton University and General Electric, and
- Battelle Process Research Unit (PRU), a gasification process being tested at Battelle Memorial Institute.

.6 Figures 4-8-1 and 4-8-2 illustrate these two technologies.

*Figure 4-8-1: Flow Diagram of Biomass-Integrated Gasifier/Steam Injected Turbine System (BIG/STIG) [Source: E. Larson & R. Williams, Princeton University]*


Hot particle clean-up
Gasifier
Prepared biomass feed stock
To process
To stack
Particles
Ash
Boost compressor
Fuel gas
Air
Heat recovery steam generator
Water
Steam
Comb.
Compressor
Steam-injected gas turbine
Turbine
Generator
Air

.7 The Brayton Cycle external combustion process is another concept which, if it can be adopted to biomass, promises the use of a widened range of biomass fuels and the opportunity for co-firing. It is illustrated in Figure 4-8-3.

.8 Canadian Solifuels Inc (CSI), along with ORTECH International, is developing a modular process in which solid wood fuel can be prepared for direct firing in the combustor of a CTU. The process, if developed, may provide increased fuel efficiency and reduced cost of biomass-fuelled generation and cogeneration at various unit sizes.

.9 Circulating Fluidized Bed Combustion (CFBC) technology utilizing biomass fuel has made great strides in the last five years. Currently installed units are of the order of 25 MW. CFBC technology is also being applied to the development of biomass gasification systems. Development issues related to biomass-fired CFBC technology include scale-up to larger unit sizes and materials and operating issues.

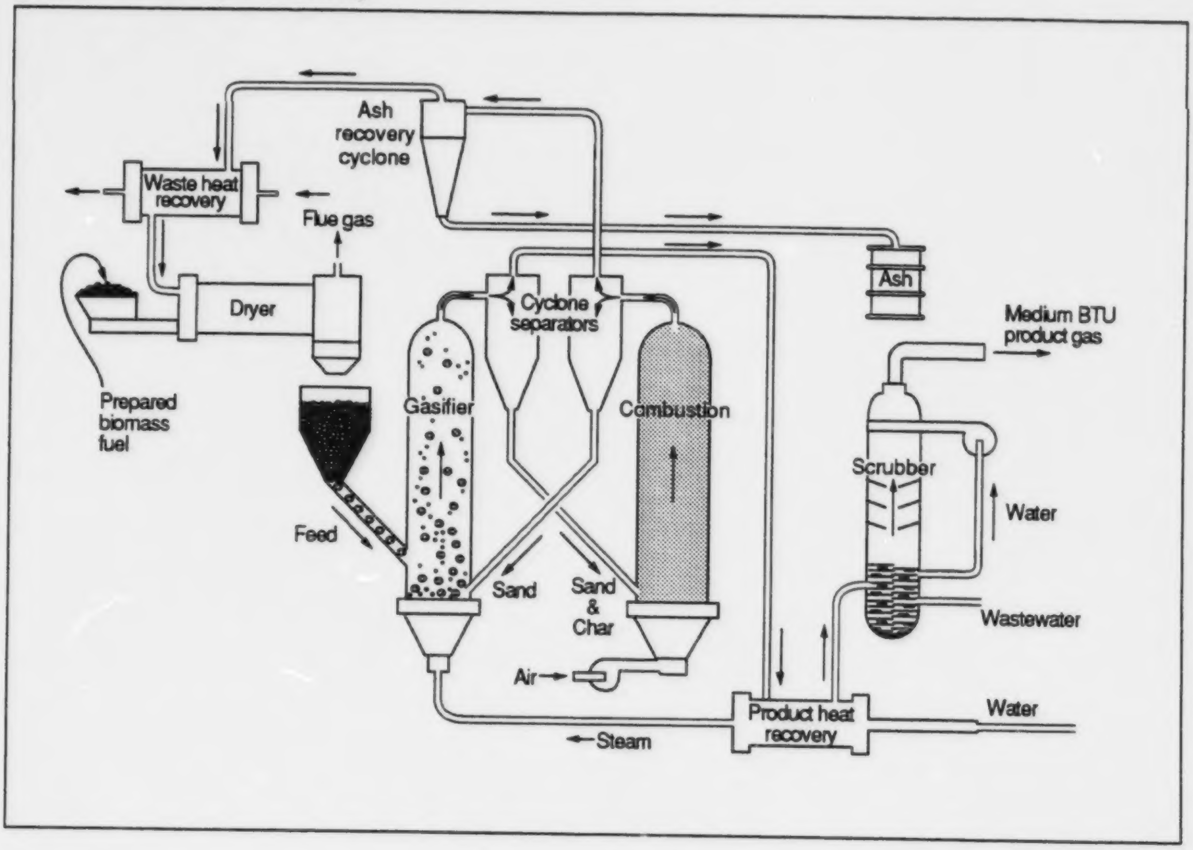
## 4-9 Options

.1 Wood-fired electricity generating units considered in this report range from 14 MW net to 70 MW net. At these two extremes, the station net heat rate at full load is expected to be 16,000 kJ/kWh for the small unit and 14,500 kJ/kWh for the larger unit. These heat rates correspond to overall plant efficiencies of 22.5 and 25 percent respectively. Boiler efficiencies for both sizes have been assumed to be 65 percent based on 50 percent moisture content in the fuel.

### 4-9-1 Biomass Option 1: 1x15 MW Wood-fuelled Station – Selection Rationale

.1 This conventional steam cycle option would consist of one unit of spreader stoker horizontal travelling grate boiler with a nominal capacity of 15 MW (14 MW net), employing mechanical draft cooling. There are limited amounts of biomass waste or plantation biomass available within economic transportation distances of any given generating site and this would be a major factor limiting station and unit size.

*Figure 4-8-2: Battelle Process Research Unit (PRU) for Gasification of Biomass and RDF [Source: Battelle Memorial Institute]*


Ash recovery cyclone
Waste heat recovery
Flue gas
Dryer
Prepared biomass fuel
Feed
Gasifier
Cyclone separators
Combustion
Ash
Medium BTU product gas
Scrubber
Water
Wastewater
Sand
Sand & Char
Air
Steam
Product heat recovery
Water

.2 There is considerable industry experience in the design, construction and operation of units of this size and type.

.3 For economic and technical reasons the station would likely be operated at an average ACF of about 80 percent providing base load generation to the grid.

.4 The station would likely be fuelled with plantation-grown willow and poplar, or fuel from selective thinning of natural forests.

.5 The station would likely be fitted with multi-cyclones and a wet-scrubber to control particulate emissions. Additional equipment to control acid gas emissions would not be required to meet current emission limits.

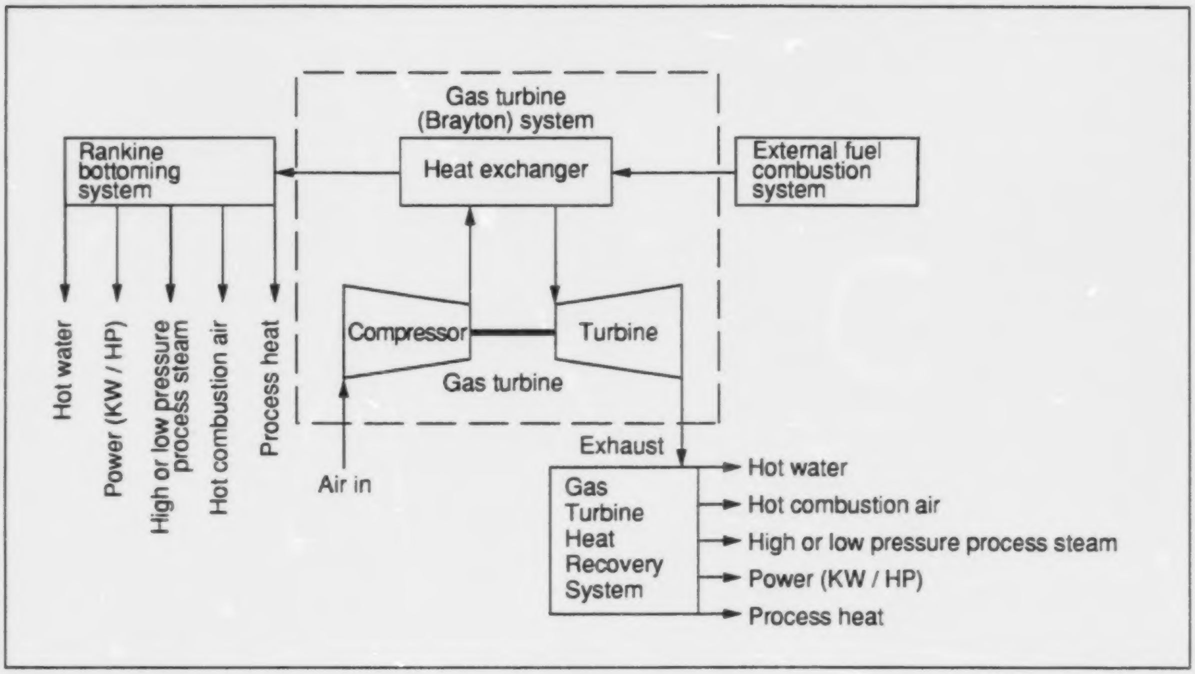
.6 The turbine-generator, its auxiliaries and balance of plant would be similar to equipment in a coal-fired plant of the same capacity.

### 4-9-2 Biomass Option 2: 1x75 MW Wood-fuelled Station – Selection Rationale

.1 This conventional steam cycle option would consist of one unit of spreader stoker horizontal travelling grate boiler with a nominal capacity of 75 MW (70 MW net). In other respects it is similar to biomass Option 1.

.2 There is little experience with stations of this size burning wood. However, this size of unit is commercially offered by major suppliers of steam generators. The turbine generator and auxiliaries are standard for this size of unit.

*Figure 4-8-3: Brayton Cycle – External Combustion System*
*[Source: L. Brizzolara Coen Co. Inc.]*



Gas turbine
(Brayton) system
Rankine bottoming system
Heat exchanger
External fuel combustion system
Hot water
Power (KW / HP)
High or low pressure process steam
Hot combustion air
Process heat
Compressor
Turbine
Gas turbine
Exhaust
Air in
Gas Turbine Heat Recovery System
Hot water
Hot combustion air
High or low pressure process steam
Power (KW / HP)
Process heat

## 4-10 Costs and Performance

.1 This section discusses the performance and cost assumptions used to estimate the levelized unit energy costs for the 15 MW and 75 MW biomass-fuelled options considered.

### 4-10-1 Performance Assumptions

.1 Figure 4-10-1 below summarizes the performance assumptions used in evaluating the levelized unit energy cost of the biomass options.

.2 Both options are assumed to be fuelled with plantation wood biomass.

### 4-10-2 Cost Estimates

.1 Ontario Hydro has no experience with the design, construction, installation and operation of biomass-fuelled power plants.

.2 The cost estimates are based mainly on reports commissioned by Ontario Hydro and prepared by experts in the field. Cost estimates are based on the most current information available to Ontario Hydro and are not site-specific. The costs are intended to provide an indication of a range of costs and not a definitive estimate of the cost of each option.

.3 The cost estimates presented are current (1991) costs.

.4 The costs presented are those for electricity as the only product. Section 4-10-5 shows the potential value of the useable heat from the two biomass options, given the assumptions about the amount and value of the heat discussed in Part 1, Section 1-7.

*Figure 4-10-1: Biomass Performance Assumptions*

| Option | Description | Useful Life (yrs.) | Annual Capacity Factor (%) | Thermal Efficiency (%) |
|---|---|---|---|---|
| 1 | 15 MW Conventional Thermal | 30 | 80 | 22.7 |
| 2 | 75 MW Conventional Thermal | 30 | 80 | 24.9 |

.5 Capital, OM&A and Fuel cost estimates for the biomass options are shown in Figure 4-10-2.

*Figure 4-10-2: Cost Estimates – Biomass Options*

| Cost Component | 15 MW Plant (Current Costs) | 75 MW Plant (Current Costs) |
|---|---|---|
| Initial Capital ($/kW) | 2,852 | 1,571 |
| Later Capital ($/kW/yr) | 14 | 8 |
| OM&A ($/kW/yr) | 174 | 69 |
| Fuel (¢/kWh) | 6.9 | 6.2 |

### 4-10-3 Levelized Unit Energy Cost Summary

.1 The levelized unit energy costs obtained using the performance and cost estimates shown above are summarized in Figure 4-10-3 for the biomass options.

*Figure 4-10-3: Levelized Unit Energy Cost Estimates – Biomass Options*

| Levelized Unit Energy Cost (LUEC) Estimates at 80% ACF (¢/kWh) | | |
|---|---|---|
| Cost Component | 15 MW Plant (Current Costs) | 75 MW Plant (Current Costs) |
| Capital | 3.7 | 2.0 |
| OM&A | 3.3 | 1.3 |
| Fuel | 6.7 | 6.2 |
| Total LUEC | 13.7 | 9.5 |

### 4-10-4 Sensitivity Ranges

.1 For each option, the sensitivities of the levelized unit energy cost to variations in the values of the individual cost components, in economic factors and in performance, are presented. Sensitivity analyses provide an indication of the variability of the levelized unit energy cost to changes in cost and performance assumptions.

.2 The cost estimates for biomass-fuelled power plants are subject to large uncertainties. These large uncertainties are reflected in the sensitivity ranges chosen.

.3 The sensitivity ranges selected are not intended to reflect a particular confidence level. The level of information available does not lend itself to such a detailed analysis. They simply represent Ontario Hydro's judgement on the possible variation of these factors.

.4 Figures 4-10-4 and 4-10-5 show the sensitivity ranges selected for costs and performance, respectively, and the effect of those ranges on the levelized unit energy costs for the two options assessed.

.5 Given the assumptions in this report regarding costs and performance, the largest range of levelized unit energy costs for each option can be obtained by assuming that all cost components and performance factors are fully dependent. That is, if one cost component increases, all cost components are assumed to increase and all performance factors are assumed to decrease, and vice-versa. In this manner, an indication of the upper and lower ranges of the levelized unit energy costs for each option is obtained. These upper and lower estimates are shown in Figure 4-10-6.

***Figure 4-10-4: Cost Component Sensitivity – Biomass Options***

| Cost Component | LUEC at 80% ACF (¢/kWh) | Range Assumed (%) | | Sensitivity (%) * | |
|---|---|---|---|---|---|
| | | Lower | Upper | Lower | Upper |
| **Option 1 – 15 MW** | | | | | |
| Capital | 3.7 | -20 | +20 | -5.4 | +5.4 |
| OM&A | 3.3 | -10 | +15 | -2.4 | +3.6 |
| Fuel | 6.7 | -33 | +45 | -16.2 | +22.1 |
| Total | 13.7 | | | -24.0 (1) | +31.1 (1) |
| **Option 2 – 75 MW** | | | | | |
| Capital | 2.0 | -20 | +20 | -4.3 | +4.3 |
| OM&A | 1.3 | -10 | +15 | -1.4 | +2.0 |
| Fuel | 6.2 | -33 | +45 | -21.5 | +29.3 |
| Total | 9.5 | | | -27.2 (1) | +35.6 (1) |

* Percentage change in total LUEC of each option.
(1) Total sensitivities are calculated assuming all cost components are fully dependent.

***Figure 4-10-5: Performance Sensitivities – Biomass Options***

| Factor | Point Estimate | Range Assumed | | Sensitivity (%) * | |
|---|---|---|---|---|---|
| | | Lower | Upper | Lower | Upper |
| **Option 1 – 15 MW** | | | | | |
| Annual Capacity Factor | 80% | 90% | 60% | -5.3 | +15.8 |
| Life (years) | 30 | 35 | 25 | -0.9 | +1.6 |
| Thermal Efficiency | 22.7% | 23.7% | 21.7% | -1.9 | +2.4 |
| **Option 2 – 75 MW** | | | | | |
| Annual Capacity Factor | 80% | 90% | 60% | -3.3 | +10.0 |
| Life (years) | 30 | 35 | 25 | -0.8 | +1.3 |
| Thermal Efficiency | 24.9% | 25.9% | 23.9% | -2.6 | +2.6 |

* Percentage change in total LUEC of each option.

### 4-10-5 Potential Value of Useable Heat

.1 The economic evaluations shown above consider electricity as the only product. Biomass-fuelled power plants may often be installed in cogeneration applications producing both electricity and useable heat. Revenues from the use or sale of heat could partially offset electricity production costs.

.2 The heat is valued on the basis of Ontario Hydro's forecast of the industrial direct price of natural gas. In addition, as discussed in Part 1, Section 1-7, it is assumed that 80 percent of the energy content of the fuel is recovered in a cogeneration application as electricity and useable heat.

.3 In this analysis it is also assumed that no additional costs would be incurred for the installation and operation of heat recovery and distribution equipment.

.4 The potential value of the useable heat produced, expressed as a levelized unit energy benefit (LUEB) is estimated to be 4.7 ¢/kWh for Option 1 and 4.1 ¢/kWh for Option 2.

*Figure 4-10-6: Overall Sensitivity – Biomass Options (All Factors Fully Dependent)*

| Option | Overall Sensitivity – LUEC (¢/kWh) | | |
|---|---|---|---|
| | Lower Estimate | Point Estimate | Upper Estimate |
| Option 1 – 15 MW | 9.6 | 13.7 | 21.4 |
| Option 2 – 75 MW | 6.3 | 9.5 | 14.7 |

### 4-10-6 Cost Summary

.1 The results in Figure 4-10-6 show that the current levelized unit energy costs of electricity from biomass-fuelled power plants range from a lower estimate of 6.3 ¢/kWh to an upper estimate of 21.4 ¢/kWh. These costs are too high to make electricity production from biomass-fuelled power plants, fuelled with plantation wood, currently economic as a source of generation for the bulk electricity system in Ontario, given that the levelized unit energy costs of conventional base-loaded generation options (for example, nuclear or conventional steam cycle coal) are projected to be in the range or 3 to 5 ¢/kWh.

.2 The use of biomass-fuelled power plants in combined heat and power applications could make these plants more economical since revenues from the use or sale of heat could partially offset electricity production costs.

## 4-11 Potential

### 4-11-1 Scenario Descriptions

.1 The potential for biomass-fuelled power plants is assessed under the three scenarios described earlier in Part 1, Section 1-8. These scenario descriptions are repeated below:

*Scenario 1:* In this scenario, it is assumed that there is no improvement in current costs and technological status by the year 2000. The potential contribution by the year 2005 is assessed.

*Scenario 2:* In this scenario, an attempt is made to account for cost and technological improvements which may occur by the year 2000. Given these improvements, the potential contribution by the year 2005 is reassessed.

*Scenario 3:* The projections in this highly speculative scenario are based on assumptions that significant improvements in technology and costs could occur by the year 2010. The potential contribution by the year 2014 is assessed.

### 4-11-2 Assumptions and Conditions

#### *Waste Wood*

.1 Most biomass combustion in Ontario is currently based on waste wood generated by industry and forestry.

.2 If all of the waste biomass currently generated, but not utilized, in Ontario could be used for electricity generation, it could support a capacity of approximately 200 MW.

.3 For all three scenarios it is assumed that only half the generated waste can be collected and used for electricity generation, and that it is available free or at negative cost delivered to the generator.

.4 For all three scenarios it is assumed that the total quantity of waste wood generated per annum will not change during the period 1991 to 2014.

#### *Plantation Biomass*

.5 Plantation biomass and natural forest selective thinning technologies are currently being developed. Scenario 1 assumes these technologies will not be in place by the year 2000.

.6 In Scenario 2 it is assumed that plantation biomass will be in demonstration phase by the year 2000, but that the price will still be relatively high at about $60 per oven dry tonne.

.7 In Scenario 3, it is assumed that plantation biomass will have been proven commercially, with a delivered price of about $40 per oven dry tonne.

.8 The projections for plantation biomass in Scenarios 2 and 3 are considered reasonable in view of the fact that demonstration and development of biomass plantation technology has proven to be a time-consuming process. Also biomass-fuelled electrical generation requires that extensive land areas must first be tested for suitability, then prepared for cultivation. First harvest would occur several years later and yields may be uncertain.

*Technology*

.9 Biomass IGCC systems are currently under development in many countries. The aim is to improve the fuel conversion efficiency from about 25 percent to as much as 40 percent. Scenario 1 assumes these technologies will not be in place by the year 2000.

.10 In Scenario 2 it is assumed that these technologies will be in the demonstration phase by the year 2000.

.11 In Scenario 3, it is assumed that these technologies will have achieved commercial viability, with progressively reducing capital and OM&A costs.

### 4-11-3 Projections of Potential

.1 The scenario assumptions lead to the following projections of capacity for biomass-fuelled generation:

| | Waste Biomass | Plantation Biomass |
|---|---|---|
| Scenario 1 | 100 MW | 0 MW |
| Scenario 2 | 100 MW | 20 MW |
| Scenario 3 | 100 MW | 100 MW |

.2 Figure 4-11-1 summarizes the above assumptions and projections.

### 4-12 Overall Assessment

.1 Biomass fuels have the following advantages over the use of conventional fossil fuels for electricity generation:

- biomass is a renewable resource, when properly managed,
- biomass is a low sulphur fuel and is considered to be carbon dioxide neutral, and
- biomass is low in ash and the ash could be returned to the forest or plantation.

.2 The technology for processing biomass fuels and for power generation from biomass has been proven in plant sizes up to 50 MW. Plant sizes up to 75 MW may be possible using conventional technology including fluidized bed combustion technology. Fluidized beds offer better $NO_x$ control. Biomass IGCC systems are reported to be in the pilot plant stage. If successfully scaled-up, these plants would increase the fuel utilization efficiency and reduce the capital costs of biomass-fuelled electricity generation.

.3 Ongoing research in several countries, including Canada, aims at developing biomass species suitable for energy plantations. Success in this area could lead to reduced costs for biomass fuels for electrical generation. Development of biomass fuels would require institutional changes in Ontario's forestry and agricultural industries.

.4 Cost is the major factor limiting the replacement of fossil fuels by biomass. Fuel costs are high, except in the case of waste wood. Because of the lower energy density of the fuel, biomass-fuelled generating stations are larger, and thus of higher capital cost, than fossil-fuelled generating stations of equivalent capacity.

.5 This review estimates the current levelized unit energy cost (LUEC) of electricity produced by plantation biomass-fuelled power plants to be in the range of 6.3 to 21.4 ¢/kWh. These costs indicate that plantation biomass-fuelled power plants are not currently economic for the production of electricity for the bulk electricity system in Ontario, if the plants are used for electricity production only.

.6 Biomass power plants could become economical sources of electricity generation when fuelled with waste biomass if the fuel is available free of charge or at negative cost. Waste biomass is used in Ontario as a source of fuel for electricity generation but is available in limited quantities. Biomass power plants also become more economic when installed in combined heat and power applications. The sale of useable heat could partially offset electricity production costs.

.7 Plants powered by biomass must be located relatively close to the fuel source (plantation or waste) because of the otherwise prohibitive costs associated with transporting the low energy density fuel.

*Figure 4-11-1: Forecast of Potential Contribution for Biomass Technology*

| Scenario | Assumptions | Major Factors Affecting Potential | Cost Compared to Conventional Generation | Potential | | Potential Applications |
|---|---|---|---|---|---|---|
| | | | | MW | By Year | |
| 1 | **Waste Biomass:**<br>• Current costs.<br>• Current technology (grate or FBC).<br>• Current availability of waste wood.<br>• Only half of waste wood used for electricity generation.<br>• Price of waste wood zero or negative.<br>• Price of plantation/forest biomass is uneconomic.<br>• Current financial incentives. | • High capital cost.<br>• Low efficiency.<br>• Price of waste wood.<br>• Availability of waste wood. | Equal to or below | 100 | 2005 | Mainly cogeneration using waste wood |
| 2 | **Common Assumptions:**<br>• No significant cost reductions.<br>• Demonstration biomass IGCC technology (increased fuel conversion efficiency).<br>• Current financial incentives. | | | | | |
| | **Waste Biomass:**<br>• As in Scenario 1. | • As in Scenario 1 | Equal to or below | 100 | 2005 | Mainly cogeneration |
| | **Plantation/Forest Biomass:**<br>• Biomass plantation and selective thinning technologies demonstrated.<br>• Price of plantation/forest biomass greater than or equal to $60/od Mg. | • High capital costs.<br>• Price of plantation biomass.<br>• Dependent on financial incentives. | Above | 20 | 2005 | Demonstration utility and/or NUG/cogen |
| 3 | **General:**<br>• Proven biomass IGCC technology.<br>• Current financial incentives (Class 34).<br>• Reduced capital cost based on larger scales of production. | • Long gestation periods and extensive R&D funding necessary to achieve viability of plantation and biomass IGCC technologies. | | | | |
| | **Waste Biomass:**<br>• Current availability of wood waste. | | Equal to or below | 100 | 2014 | NUG/cogen |
| | **Plantation/Forest Biomass:**<br>• Selective thinning and plantation technologies proven.<br>• Reduced fuelling cost because of proven technology.<br>• $40/od tonnes. | | Equal to or below | 100 | 2014 | Utility/NUG/cogen |

.8 As discussed in Section 4-11, the potential contribution of biomass-fuelled power plants to the electricity supply mix in Ontario (in addition to capacity currently installed) could be another 100 MW by the year 2005 if only waste biomass is utilized. Biomass-fuelled capacity could increase by a further 100 MW by the year 2014, if plantation biomass becomes viable and costs decline.

.9 Biomass-fuelled generating facilities might provide local economic stimulus but the potential exists for localized community impacts. Changes in current institutions and practices within Ontario's forestry and agriculture sectors would be required to support the adoption of biomass waste gathering processes, sustained yield forests, and sustainable plantations and/or agricultural activities.

.10 In summary, the advantages of biomass as a fuel for electricity generation include:

- renewable resource, when properly managed,
- lower emissions of sulphur dioxide than fossil-fuelled generation,
- potential to be carbon dioxide neutral, and
- low in ash and the ash could be returned to the forest or plantation.

.11 The current barriers to wide scale introduction of plantation biomass-fuelled electricity generation in Ontario include:

- high capital cost of the plant,
- limited supplies of biomass waste,
- anticipated high cost of plantation grown fuel production and transportation,
- significant land requirements for the plantations, and
- relatively low thermal efficiencies of existing biomass combustion technologies.

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Ontario Hydro, September 1990, **Alternative Energy Study – Review of Technologies and Costs for the Generation of Electricity from Wood**, A. Ismail/ Monenco Consultants Limited, Ontario Hydro, D&D Report No. 90352.

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### 4-13-1 Additional Reading

Dunster, J., 1989, **Sustainable Community Forestry, Phase I Report**, Conservation Council of Ontario, Toronto, 1989.

# Part 2: Technology Assessment

## Chapter 5: Peat

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## 5-1 Introduction

.1 The purpose of this chapter is to describe existing and developing peat-electric technologies and to evaluate their potential for application in Ontario.

.2 Apart from the systems specific to milled peat, which are discussed in this chapter, the solid fuel combustion technologies described in Appendix B are generally applicable to peat-fuelled electrical generation.

.3 The technologies available for the production of energy from peat are illustrated in Figure 5-1-1.

.4 The major challenge with respect to the use of peat lies in the development of cost-effective and environmentally acceptable methods of mining and dewatering raw peat for the preparation of peat fuels.

## 5-2 Fuel/Energy Source

### 5-2-1 Reserves

.1 Peat is dead vegetation such as grass and moss which has been accumulating in bogs, a few millimetres each year, since the last ice age. Peat is sometimes described as a young coal and sometimes as an old biomass.

.2 Peat resources can generally be divided into two major utilization groups, energy use peat and non-energy use peat. The latter group, which includes sphagnum peats, are used mainly in horticulture and as feedstocks for activated carbon, sorbents, waxes and chemicals.

.3 Peat is not a uniform substance since the degree to which materials have decomposed or "humified" increases with the age and depth of the layers of peat in a bog.

.4 Peat in its natural state contains both free and bound water averaging about 90 percent moisture content in total.

.5 Figures 5-2-1 and 5-2-2 tabulate world and Canadian peat resources, as inferred from aerial mapping.

.6 By some estimates, peatlands (bogs, fens, swamps and marshes) cover as much as 12 percent of Canada, and some of the world's most intensive peat formation areas exist in Ontario.

.7 Ontario's peat deposits are located primarily in the northern and southeastern parts of the province as indicated in Figure 5-2-3. Corresponding survey data for southwestern Ontario are unavailable.

*Figure 5-1-1: Technologies for Production of Energy from Peat*

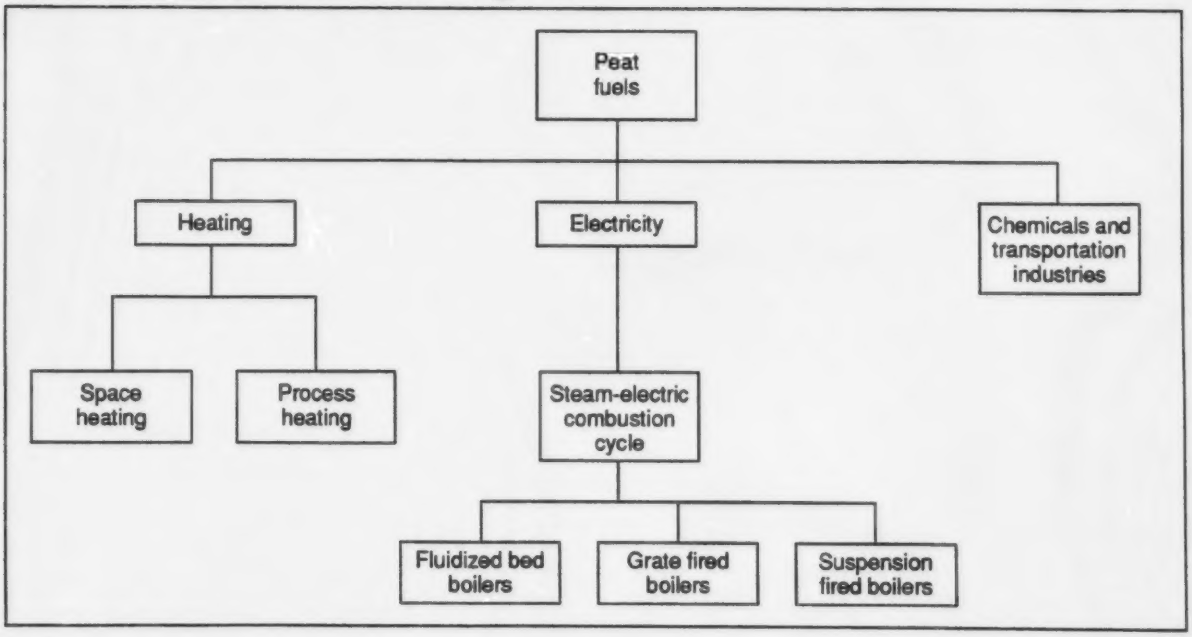


***Figure 5-2-1: World Peat Resources [Kivinen & Pakarinen, 1980]***

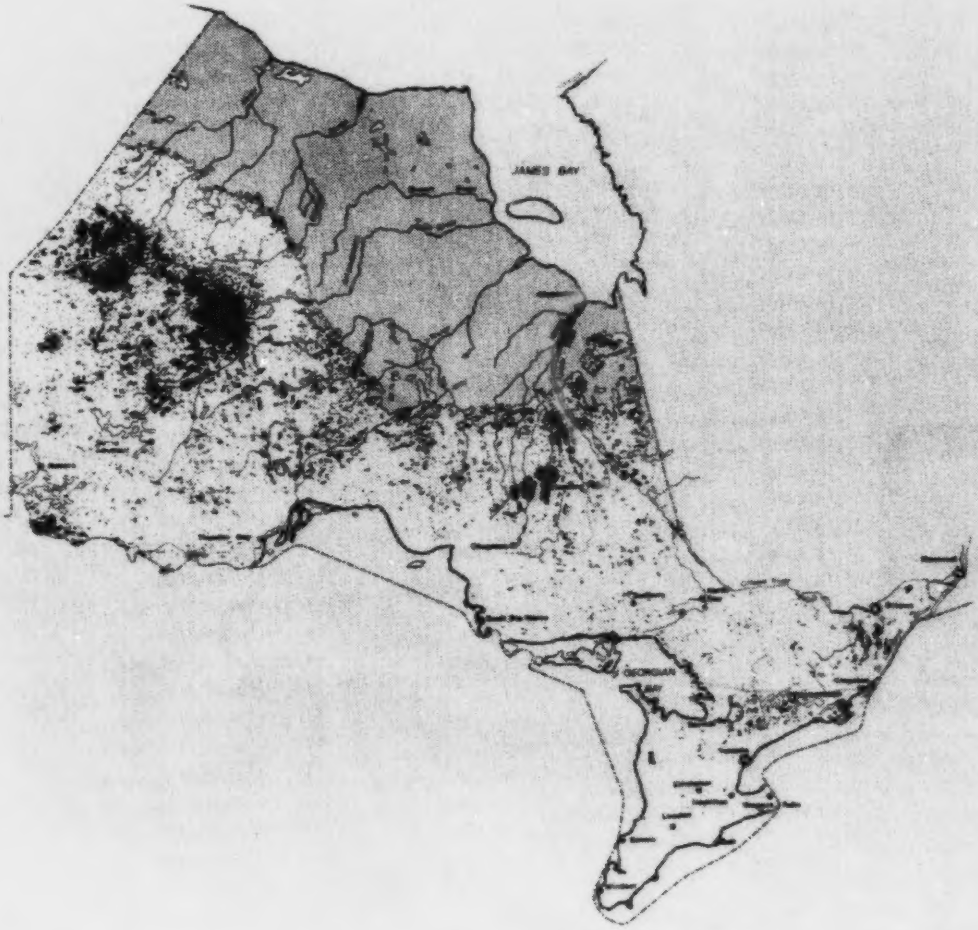
| Country | Biological Peatland ha x $10^6$ | Peat Annual Production Tonnes x $10^3$ | | Total |
|---|---|---|---|---|
| | | Fuel Peat | Moss Peat | |
| Canada | 170.0 | - | 488 | 488 |
| U.S.S.R. | 150.0 | 80,000 | 120,000 | 200,000 |
| U.S.A. | 40.0 | - | 800 | 800 |
| Indonesia | 26.0 | - | - | - |
| Finland | 10.0 | 3,100 | 500 | 3,600 |
| Sweden | 7.0 | - | 270 | 270 |
| China | 3.5 | 800 | 1,300 | 2,100 |
| Norway | 3.0 | 1 | 83 | 84 |
| Malaysia | 2.4 | - | - | - |
| United Kingdom | 1.6 | 50 | 500 | 550 |
| Poland | 1.4 | - | 280 | 280 |
| Ireland | 1.2 | 5,570 | 380 | 5,950 |
| West Germany | 1.1 | 250 | 2,000 | 2,250 |
| Total | 417.2 | 89,771 | 126,601 | 216,372 |
| Total (Approximate) | 420.0 | 90,000 | 130,000 | 220,000 |

***Figure 5-2-2: Peat Resources of Canada [Tibbets, 1980]***

| Province | Potential / Inferred *Peat Resources* | | Measured *Peat Resources* | | % of Total Peatland Area |
|---|---|---|---|---|---|
| | Hectares | Tonnes* x $10^6$ | Hectares | Tonnes x $10^6$ | |
| Newfoundland | 2,000,000 | 3,400 | 360,000 | 612 | 18.0 |
| Nova Scotia | 10,000 | 45 | 5,100 | 23 | 50.0 |
| P.E.I. | 2,000 | 2 | 2,000 | 2 | 100.0 |
| New Brunswick | 100,000 | 170 | 60,000 | 103 | 60.0 |
| Quebec | 12,000,000 | 20,680 | 50,000 | 64 | 0.4 |
| Ontario | 16,000,000 | 27,580 | 62,000 | 135 | 0.4 |
| Manitoba | 5,500,000 | 9,525 | 106,000 | 103 | 2.9 |
| Saskatchewan | 4,000,000 | 6,890 | 16,000 | 27 | 0.4 |
| Alberta | 10,000,000 | 17,240 | 1,600 | 3 | 0.2 |
| British Columbia | 970,000 | 1,630 | 6,000 | 20 | 0.6 |
| NWT and Yukon | | – Not Available – | | | |
| Total | 50,582,000 | 87,162 | 668,700 | 1,092 | 1.3 |

* At 50% moisture

*Figure 5-2-3: Peat Deposits – Ontario [Tibbetts, 1980; OMNR, 1981]*



Estimated regional peat resources of Ontario

| | Unit | Northeastern Ontario | Northwestern Ontario | Southeastern Ontario | Total |
|---|---|---|---|---|---|
| Total estimated peatland area | millions ha | 1.6 | 0.70 | 0.39 | 2.69 |
| Peatlands judged to have good resource recovery potential | millions ha | 0.43 | 0.26 | 0.12 | 0.81 |
| Estimated in-situ volume | million $m^3$ | 8,900 | 6,900 | 2,750 | 18.55 |
| Number of peatlands greater than 100 ha each | # | 1,500 | 1,400 | 760 | 3660 |
| Estimated proportion of fuel grade peat | % | 67 | 50+ | 90 | 65+ |

.8 Estimates of Ontario's peat resources vary considerably.

.9 Figure 5-2-2 (Tibbetts, 1980) shows estimates of Ontario peatlands covering 16 million hectares and containing 27,580 million tonnes of peat at an equivalent of 50 percent moisture content (i.e., equal to 13,790 million tonnes of dry peat). It should be noted that Tibbetts' estimates are 'inferred' from data obtained by aerial or satellite mapping. It is necessary that such estimates be confirmed by field and laboratory investigation.

.10 Figure 5-2-3 shows Ontario Geological Survey (OGS) estimates for selected areas of peatlands in three regions of Ontario, the totals for which are 2.69 million hectares containing 18.55 million cubic metres of in-situ peat. The OGS estimates have a degree of confirmation from field studies and from laboratory analyses of samples.

.11 From Tibbetts' data, it can be computed that, if (hypothetically) all of Ontario's peat resources could be applied to power generation, they would potentially fuel an electrical generation capacity of 364,000 MW for 30 years (at 25 percent fuel-electric efficiency).

.12 From OGS data, it can be computed that, if (hypothetically) all of the resources in the peatlands which are "judged (by OGS) to have good resource recovery potential", are applied to power generation, they would, potentially, fuel an electrical capacity of 12,500 MW for 30 years (at 25 percent fuel-electric efficiency).

.13 A report prepared for Ontario Hydro (Ismail/Monenco, 1989) considers that if about 40 percent of the recoverable peat resource estimated by OGS could, in practice, be mined for power generation, then this represents the maximum 'technical' potential for peat-fuelled electrical generation in Ontario and equals 5000 MW of electrical generating capacity for 30 years. This number of 5000 MW is a mere 1.37 percent of the 364,400 MW capacity which has been computed when using Tibbetts' estimates of Ontario's peat resource.

.14 As shown in Figure 5-2-3 southeastern Ontario's reserves contain an estimated 90 percent fuel grade peat. The potential for large-scale operations is limited by a number of factors including the small sizes of individual bogs, high density tree cover, and high stump and wood content.

.15 Peat reserves in northwestern and northeastern Ontario may offer a technical resource recovery potential using conventional peat extraction methods given favourable climatic and demographic factors.

.16 To date Ontario's harvested peat has been used for horticultural purposes. None has yet been used to generate electricity. It has been estimated that Ontario produces about one percent of Canada's horticultural peat.

### 5-2-2 Properties of Peat

.1 The physical and chemical processes which take place during accumulation are complex and result in a wide variety of peat properties.

.2 Peat is classified on the basis of its humification (decomposition), in a range of one to 10 known as the von Post scale. Generally, peats classified H1 to H3 on the von Post scale are considered good for horticultural use, being basically sphagnum peats. Older peats, those classed H5 to H10, are considered fuel peats. They are progressively more colloidal (i.e., the peat particles suspended in water are microscopic) and non-fibrous.

.3 Figures 5-2-4, 5-2-5 and 5-2-6 identify selected physical and chemical properties of Ontario peats at the various humification levels. They illustrate how some properties of peat increase or decrease with depth and humification; for example, ash content increases with depth. Some properties indicate no clear trend; that is, they are not necessarily dependent on age or on peat location in the bog.

.4 Peat contains water in two main forms – free, unbound water which can drain, evaporate or be pressed out, and bound water contained in the micropore sacs which have not decomposed.

.5 Figure 5-2-7 compares the chemical and physical properties of peat and other fuels.

.6 The figure illustrates that peat's heating value is less than those of heavy fuel oil and bituminous coal, but similar to those of lignite and wood.

*Figure 5-2-4: Variation of Peat Fuel Properties with Humification – Northwestern Ontario*

| Properties | Humification | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | H1 | H2 | H3 | H4 | H5 | H6 | H7 | H8 |
| Ash content (%) | 2.5 | 4.0 | 6.4 | 7.2 | 7.3 | 9.6 | 7.4 | 10.4 |
| Net heating value (cal/g) | 4309 | 4307 | 4631 | 4619 | 4620 | 4475 | 4603 | 4532 |
| Volatile matter (%) | 78.6 | 76.3 | 70.1 | 67.0 | 66.5 | 64.5 | 66.1 | 61.9 |
| Total carbon (%) | 48.7 | 48.7 | 50.2 | 51.4 | 50.7 | 48.5 | 52.7 | 47.0 |
| Fiber content (%) | 94.1 | 79.5 | 58.2 | 50.6 | 41.0 | 39.0 | 48.0 | 48.5 |
| Peat pH ($H_2O$) | 4.40 | 4.7 | 5.5 | 5.7 | 5.8 | 5.8 | 5.2 | 6.6 |

Source : Ontario Geological Survey

*Figure 5-2-5: Variation of Peat Fuel Properties with Humification – Northeastern Ontario*

| Properties | Humification | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | H1 | H2 | H3 | H4 | H5 | H6 | H7 | H8 |
| Ash content (%) | 7.7 | 6.7 | 6.2 | 7.6 | 9.2 | 9.3 | 11.1 | 11.7 |
| Net heating value (cal/g) | 4128 | 4284 | 4608 | 4623 | 4605 | 4579 | 4428 | 4531 |
| Volatile matter (%) | 74.7 | 72.9 | 70.8 | 67.3 | 65.9 | 66.0 | 61.9 | 66.3 |
| Total carbon (%) | 47.5 | 47.4 | 51.1 | 51.8 | 51.3 | 51.9 | 49.4 | 52.0 |
| Fiber content (%) | 82.6 | 73.5 | 59.2 | 51.3 | 48.8 | 51.9 | 50.4 | 58.0 |
| Peat pH ($H_2O$) | 5.1 | 5.2 | 4.9 | 5.3 | 5.5 | 5.4 | 5.3 | 5.5 |

Source : Ontario Geological Survey

*Figure 5-2-6: Variation of Peat Fuel Properties with Humification – Southeastern Ontario*

| Properties | Humification | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | H1 | H2 | H3 | H4 | H5 | H6 | H7 | H8 |
| Ash content (%) | 5.5 | 6.2 | 6.9 | 7.4 | 7.8 | 11.3 | 10.9 | 10.3 |
| Net heating value (cal/g) | 4299 | 4384 | 4493 | 4635 | 4773 | 4670 | 4642 | 4880 |
| Volatile matter (%) | 75.5 | 73.6 | 68.0 | 66.5 | 65.8 | 65.0 | 64.0 | 65.2 |
| Total carbon (%) | 48.3 | 47.1 | 49.0 | 50.4 | 51.4 | 50.3 | 50.0 | 52.2 |
| Fiber content (%) | 82.3 | 74.1 | 52.2 | 42.5 | 40.2 | 40.0 | 40.2 | 41.4 |
| Peat pH ($H_2O$) | 4.5 | 5.1 | 6.1 | 5.8 | 5.6 | 5.7 | 5.6 | 5.1 |

Source : Ontario Geological Survey

*Figure 5-2-7: Comparison of Peat with Other Fuels*

| | Heavy fuel oil | Coal (bituminous) | Lignite | Peat | Wood |
|---|---|---|---|---|---|
| C % | 83-86 | 76-87 | 65-75 | 50-60 | 48-50 |
| H % | 11.5-12.5 | 3.5-5.0 | 4.5-5.5 | 5.0-6.5 | 6.0-6.5 |
| O % | 1.5-2.5 | 2.8-11.3 | 20-30 | 30-40 | 38-42 |
| N % | 0.2-0.3 | 0.8-1.2 | 1-2 | 1.0-2.5 | 0.5-2.3 |
| S % | 2.0-2.8 | 1.0-3.0 | 1-3 | 0.1-0.2 | <0.1 |
| Ash content % | 0.3 | 4-10 | 6-10 | 2-10 | 0.4-0.6 |
| Volatiles % | | 10-50 | 50-60 | 60-70 | 75-85 |
| Bulk density kg/m$^3$ | 920-970 | 720-880 | 650-780 | 100-400 | 320-420 |
| Operational moisture % | 0.1 | 3-8 | 40-60 | 40-60 | 30-55 |
| Typical higher heating value (dry basis) MJ/kg | 42 | 30 | 22 | 20 | 20 |

### 5-2-3 Forms of Peat Fuel

.1 Raw peat excavated from a bog can be processed into solid, liquid and gaseous fuels.

.2 Solid fuel peat can be hand cut and dried at the bog as "sod" or it can be mined and processed as "milled peat", and, if drained, densified to produce peat briquettes, or pellets as pictured in Figure 5-2-8.

.3 Sods are blocks of peat material in cylindrical or brick form which are produced from the top of a drained bog and air dried in ridged heaps to about 30 percent moisture content (m.c.) by weight.

.4 Peat can be dried to below 15 percent m.c. and densified to form briquettes or pellets which, though expensive, are more economically and safely transported than non-densified solid peat fuels. They also have more uniform combustion properties than other solid peat fuels and do not produce dust.

.5 Milled, or loose dried peat, is a light and powdery material similar in colour and appearance to horticultural peat.

.6 Peat can be processed to produce methanol which can be used as a petroleum substitute in the transportation and chemical industries. This has not been shown to be cost-effective at current energy prices.

.7 Peat can be fermented to produce ethanol, or subjected to anaerobic digestion to produce a low energy content biogas. Peat can also be processed into liquid hydrocarbon fuel by indirect hydrogenation in a manner similar to that employed with biomass. For the purpose of this report none of these techniques has been considered as likely to produce cost-effective fuel for electricity generation.

.8 Pyrolytic gasification can also be employed to produce a low to medium heating value biogas, as with wood. Such a gas could be burned in a gas turbine or engine to generate electricity. However, the higher ash content of peat would make this technically more difficult than would be the case using wood.

.9 Figure 5-2-9 illustrates the range of values for selected properties of solid peat fuels and raw peat.

*Figure 5-2-8: Various Forms of Solid Peat Fuel*
*[Courtesy of Ekono Ltd.]*

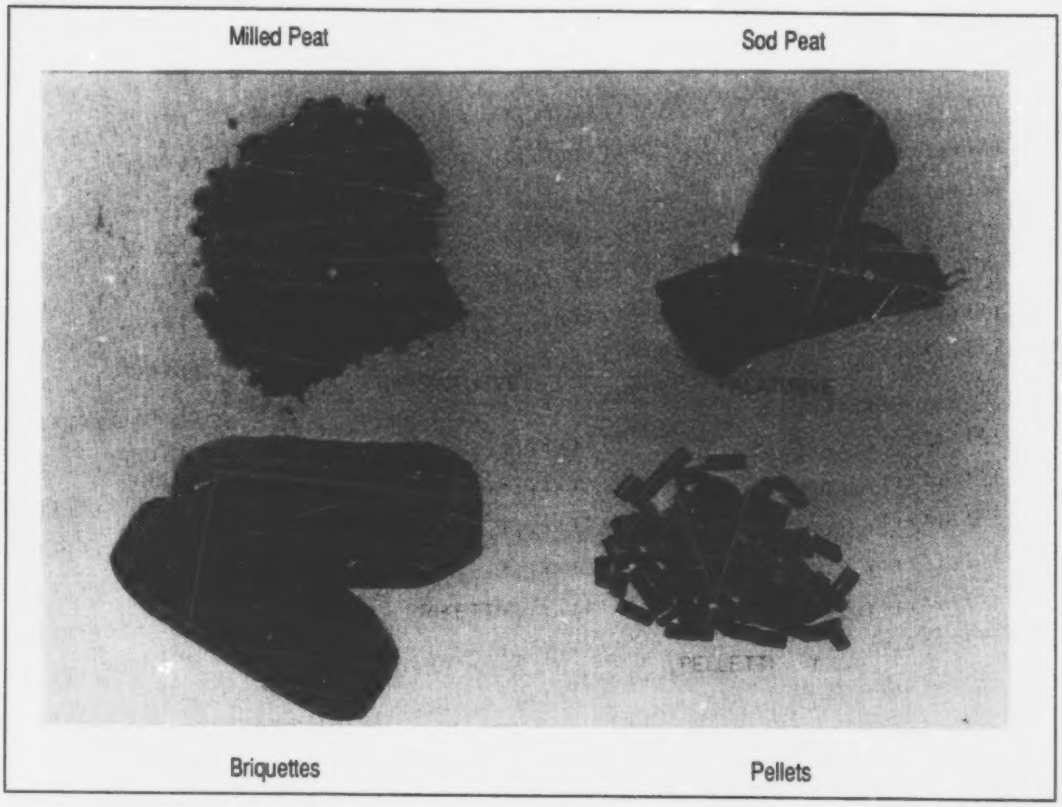


*Figure 5-2-9: Properties of Raw Peat and Peat Fuels*

| Fuel Type | Moisture Content | | Bulk Density | | Heating Value (As Received Basis) | |
|---|---|---|---|---|---|---|
| | Typical % | Range % | Typical $kg/m^3$ | Range $kg/m^3$ | Typical GJ/tonnes | Range GJ/tonnes |
| 1. Raw Peat (In-situ) | 90 | 85-95 | 1000 | 950-1050 | 2.0 | 1.0-3.0 |
| 2. Milled Peat | 50 | 40-65 | 360 | 180-480 | 10.00 | 9.0-12 |
| 3. Sod Peat | 30 | 25-45 | 320 | 250-450 | 13.00 | 11-14 |
| 4. Briquettes/Pellets | 12 | 10-15 | 850 | 700-1000 | 18.50 | 17-20 |

## 5-2-4 Peat Extraction and Processing

*General*

.1 Peat should have an average moisture content not exceeding 50 percent for sustained combustion in a steam generating furnace.

.2 In-situ peat typically contains 90 percent water by weight, and it's bulk density is close to that of water (1000 kg/m$^3$). Peat can be used as a fuel only when it has been dewatered to a moisture content of 50 percent or less. Its bulk density at 50 percent moisture content generally ranges from 180 to 450 kg/m$^3$. It is important, therefore, that any specification of fuel peat include its percentage of moisture by weight and its bulk density. If peat fuel at 50 percent moisture content is stated, this means that 89 percent of the original water from the in-situ bog peat has been removed. Sphagnum peats can hold from 15 to 30 times their weight in water.

.3 The dewatering of peat is difficult and expensive, but must be achieved in order to produce peat fuel containing 50 percent moisture content or less.

.4 The combinations of processes at bog and at the plant must be selected to suit the characteristics of:

- the bog,
- the climate,
- the virgin peat,
- environmental compliance, and
- the economics of producing the end product to desired specifications.

.5 Free, or unbound water can be removed by draining, evaporating, centrifuging and pressure filtering the peat.

.6 There are also various methods of removing bound water. The choice of method depends on the desired end product and on the available feedstock.

.7 Bound water can be removed by natural decomposition of the fibres. Decomposition occurs naturally in the bog, but the process is very slow.

.8 Other methods of releasing bound water involve rapid heating using hot gases such as flue gas or steam. The water in micropores, thus heated, converts to steam and escapes its bonds.

.9 There are essentially two processes, "dry" and "wet" mining, by which peat can be extracted from the bog and dried for use as fuel.

.10 There are several variations of each of the two processes, the choice of which is largely determined by the size and depth characteristics of particular peat bogs and the distances between them.

***Dry Mining***

.11 "Dry mining" techniques are used to produce "sod" and "milled" peat fuels.

.12 The dry mining process requires extensive bog preparation – clearing, grading, levelling and drainage ditch construction – a process which can take from two to seven years before fuel production begins.

.13 Ditching and controlled draining is critical both for the success of dry mining and for preventing damage to local watercourses.

.14 Both milled and sod peat are obtained from the top of a bog which has been cleared and cambered to a road-like profile to promote runoff and drainage as shown in Figure 5-2-10.

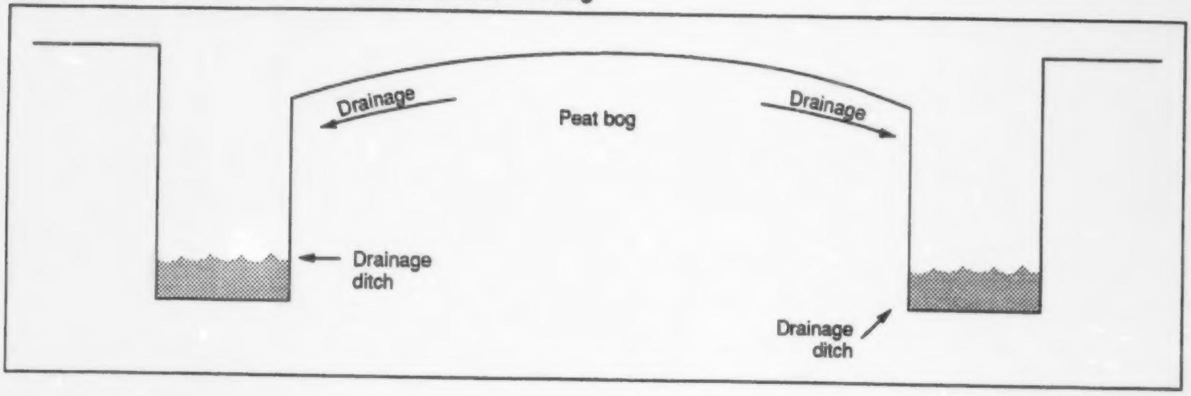
.15 Sods are cut or extruded from the top of a bog, stacked in ridged heaps and air dried to about 30 percent moisture content.

.16 Milled peat is obtained from a similarly prepared bog.

.17 Milling is a repetitive process in which a thin upper layer the top centimetre of a prepared bog is harrowed (milled), allowed to dry in the sun and air, turned again and further dried to about 50 percent moisture content before it is removed by suction or by mechanical systems.

.18 After each layer has been milled, dried and removed, the process is repeated.

*Figure 5-2-10: Cross Section of a Cleared, Graded Peat Bog*



.19 Sod peat production and the milling process require warm, dry climatic conditions. Rainfall can set the drying process back by days or weeks, greatly affecting the seasonal harvest each year. In northern Ontario's climate the whole annual fuel requirement must be "dry-mined" in a short summer season. Weather conditions in Ontario permit an average of 10 harvests of milled peat per season, on average, yielding 150 to 200 tonnes per hectare, at a nominal 50 percent moisture content.

.20 Dry mining presents logistical problems involving the need to assemble intensive manpower and heavy equipment for a short season each year.

.21 The milling process permits about 65 percent recovery of peat from a bog. But this can vary greatly with the depth and cross sectional characteristics of the bog being mined.

.22 Using the milling process, an Ontario bog of about 1080 hectares, approximately three metres deep, could provide enough fuel to operate a 15 MW generating station for about 30 years at 80 percent ACF.

.23 Densified fuels such as briquettes and pellets, which typically have 10 percent moisture content, can be produced by further drying and then densifying milled peat (which has 50 percent m.c.) or sod peat (which has 30 percent m.c.).

### *Wet Mining*

.24 Technology is being developed to use backhoes, dredges, high pressure water jets, or other equipment to "wet mine" peat as a slurry which is piped to a dewatering plant.

.25 Considerable research and development effort has been applied to the development of wet mining and slurry fuel systems because of difficulties posed by dry mining techniques particularly in the case of relatively small and shallow bogs.

.26 "Wet mining" techniques can be used to produce a slurry which can be piped to a nearby fuel preparation plant.

.27 Water must sometimes be added to the slurry to bring it to a consistency suited to pumping. At more than 10 percent solids content the slurry becomes too difficult to pump, while at less than 5 percent solids the slurry becomes difficult to dewater.

.28 Wet mining does not require that a bog be prepared and drained over a two to seven year period as is required for dry mining; however, the peatland must be cleared of its overburden of shrubs and trees.

.29 It is estimated that the wet mining process will permit about 80 percent of the peat to be recovered from a bog, about 15 percent more than can be recovered by dry mining systems. However, the process has not been demonstrated commercially to date.

.30 Figure 5-2-11 tabulates the relation between peat, its moisture content, and its end use.

.31 Figures 5-2-12, 5-2-13 and 5-2-14 illustrate various combinations of processes for producing peat fuels.

*Figure 5-2-11: Water Content of Typical Peat Materials*
*[Source: Monenco Consultants Limited]*

| | Material/ Product | Moisture content (%) | End use for which typically suitable | Product composition from 100 kg Original weight of raw peat | | Weight after water removal (Addition)* | Water removed (Added)* | Percentage of water removed (Added)* |
|---|---|---|---|---|---|---|---|---|
| | | | | Water kg | Solids kg | kg | kg | % |
| 1 | Raw peat | 90 | — | 90.00 | 10.00 | 100 | — | — |
| 2.a | Peat slurry | 90 | Requires dewatering to produce peat fuels | 90.00 | 10.00 | 100 | 0 | 0 |
| 2.b | Peat slurry | 96 | | 240 | 10.00 | (250) | (150) | (167) |
| 2.c | Peat slurry | 97 | | 323 | 10.00 | (333) | (233) | (259) |
| 3 | Mechanically dewatered peat | 70 | Requires dewatering to produce peat fuels | 23.33 | 10.00 | 33.33 | 66.67 | 74.1 |
| 4 | Peat fuel | 50 (or lower) | Suitable as combustion fuel | 10.00 | 10.00 | 20.00 | 80.00 | 88.9 |
| 5 | Peat fuel | 35 (or lower) | Suitable as gasification fuel | 5.38 | 10.00 | 15.38 | 84.62 | 94.0 |
| 6 | Peat fuel | 10 (or lower) | Suitable for densification (Pelletizing/ briquetting) | 1.10 | 10.00 | 11.10 | 88.90 | 98.8 |

* Note : It may be necessary to add water to raw peat to produce a pumpable slurry.

*Figure 5-2-12: Dry Mining "Milled" and "Sod" Peat Systems [after Monenco, 1990]*

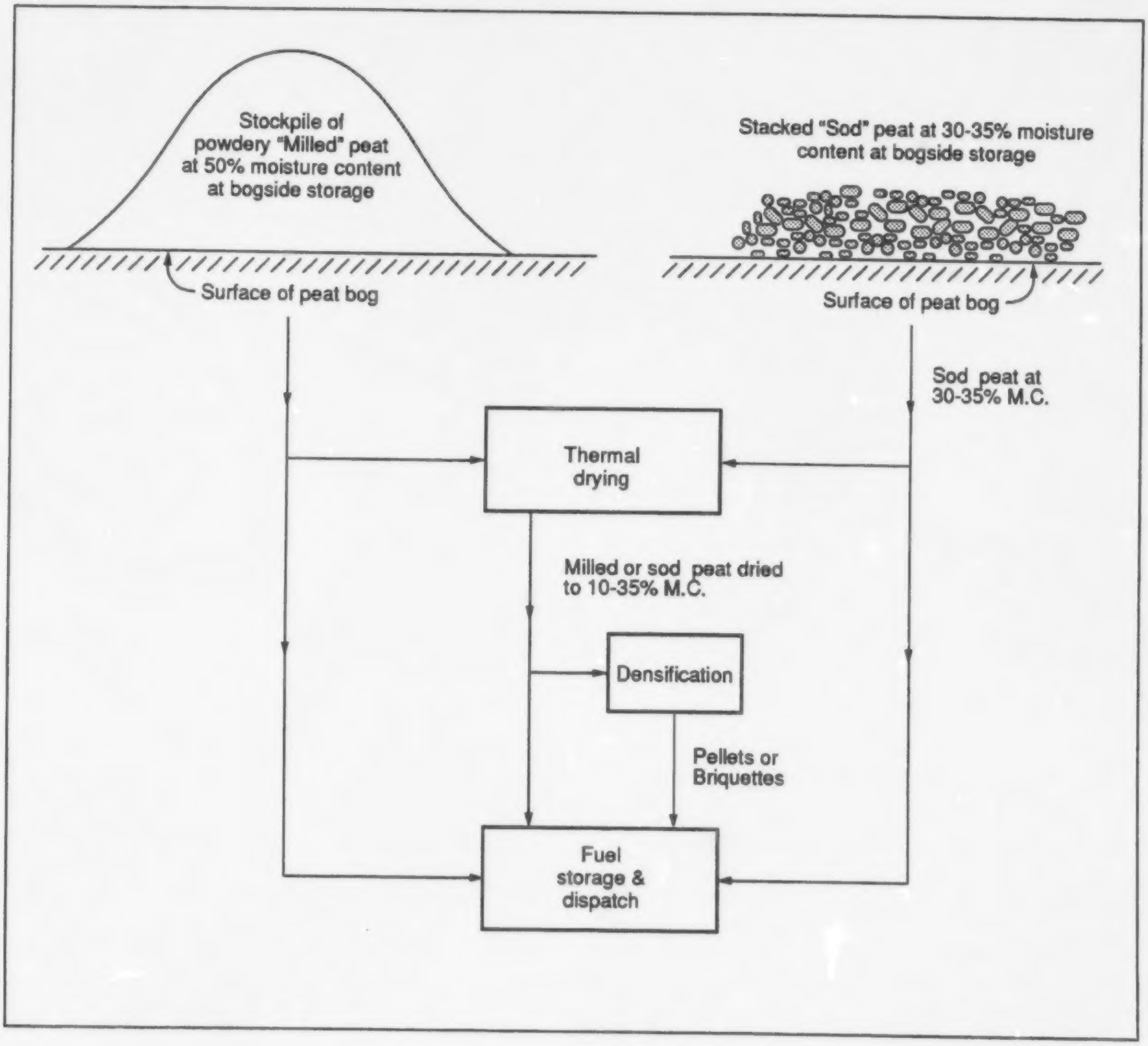
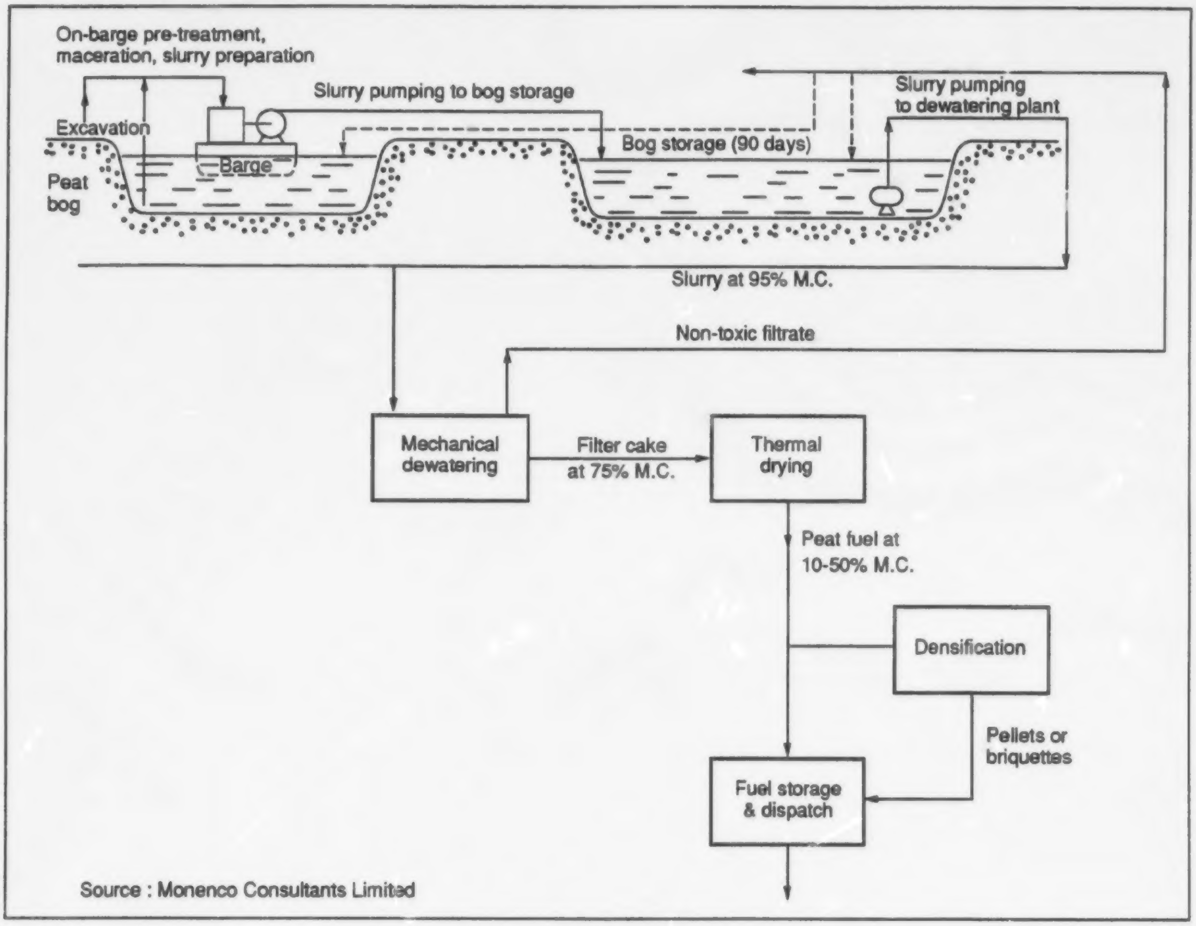

Stockpile of powdery "Milled" peat at 50% moisture content at bogside storage
Surface of peat bog
Stacked "Sod" peat at 30-35% moisture content at bogside storage
Surface of peat bog
Sod peat at 30-35% M.C.
Thermal drying
Milled or sod peat dried to 10-35% M.C.
Densification
Pellets or Briquettes
Fuel storage & dispatch

*Figure 5-2-13: Wet Mined and Slurried Peat System – Peat Dewatering and Drying Plant without Thermal Treatment*


On-barge pre-treatment, maceration, slurry preparation
Slurry pumping to bog storage
Slurry pumping to dewatering plant
Excavation
Barge
Bog storage (90 days)
Peat bog
Slurry at 95% M.C.
Non-toxic filtrate
Mechanical dewatering
Filter cake at 75% M.C.
Thermal drying
Peat fuel at 10-50% M.C.
Densification
Pellets or briquettes
Fuel storage & dispatch

Source : Monenco Consultants Limited

## 5-3 Technology Description

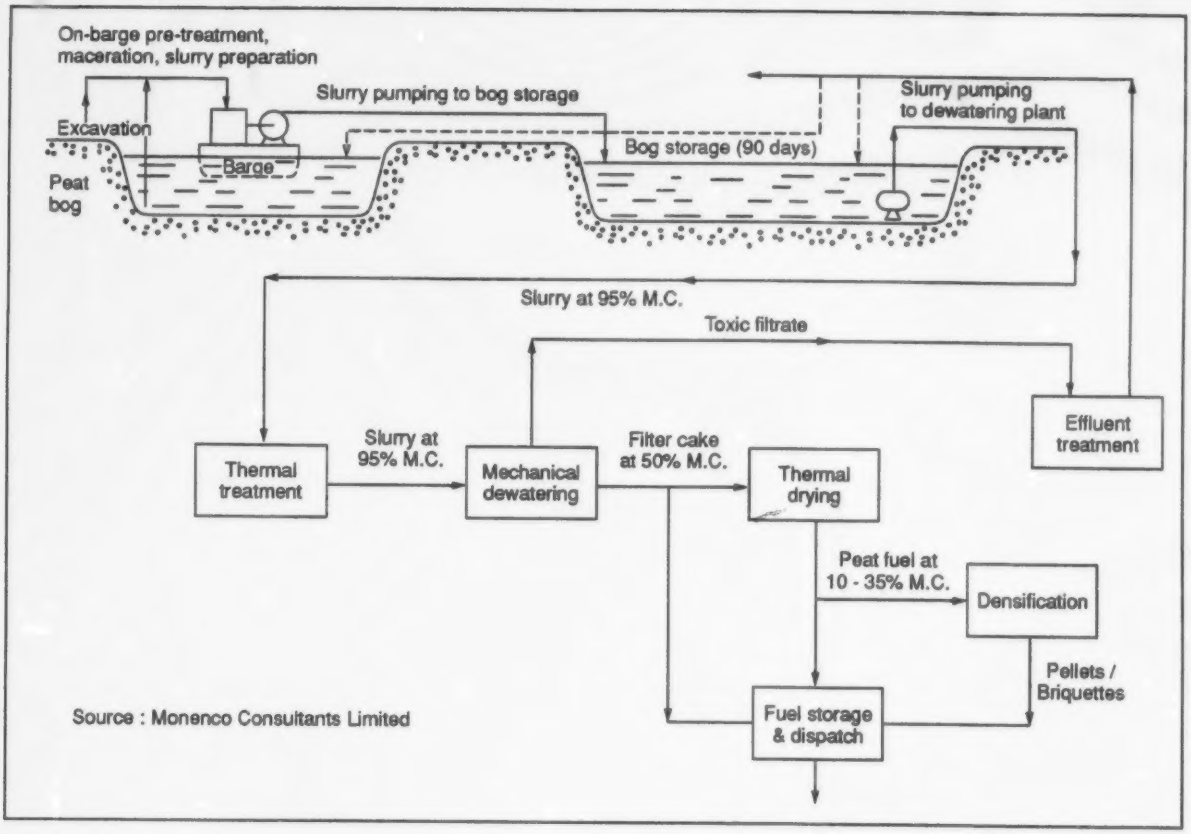
.1 Like biomass-fired plants, peat-fired generating stations are basically "mine-mouth" power plants because peat, like wood, requires large land areas on which to accumulate, and because both fuels have high moisture contents (about 50 percent), low bulk densities (around 300 kg/m$^3$) and low energy densities (around 10 gigajoules per tonne).

.2 Stations fuelled with dry-mined peat have been located up to 100 km from the bog, although they are usually closer.

.3 To date all peat-fuelled electrical energy has been generated by firing "dry-mined" fuels. This is considered "conventional" peat-fuelled power generation technology. Liquid fuels are not being commercially produced from peat at present.

.4 The steam electric systems used to derive electricity from fuel peat are very much the same as those described and illustrated in Appendix B.

*Figure 5-2-14: Wet-Mined and Slurried Peat System –*
*Peat Dewatering and Drying Plant with Thermal Treatment*


On-barge pre-treatment, maceration, slurry preparation
Slurry pumping to bog storage
Excavation
Peat bog
Barge
Bog storage (90 days)
Slurry pumping to dewatering plant
Slurry at 95% M.C.
Toxic filtrate
Effluent treatment
Thermal treatment
Slurry at 95% M.C.
Mechanical dewatering
Filter cake at 50% M.C.
Thermal drying
Peat fuel at 10 - 35% M.C.
Densification
Pellets / Briquettes
Fuel storage & dispatch

Source : Monenco Consultants Limited

.5 Peat's relatively low energy content and high moisture content require that peat-fired boilers and fuel handling systems be different from, and much larger than, those for coal or oil-fired units.

.6 Peat's high volatiles content and the need to ensure complete combustion of the peat particles necessitate a long flame pattern, a factor which also tends to increase boiler size.

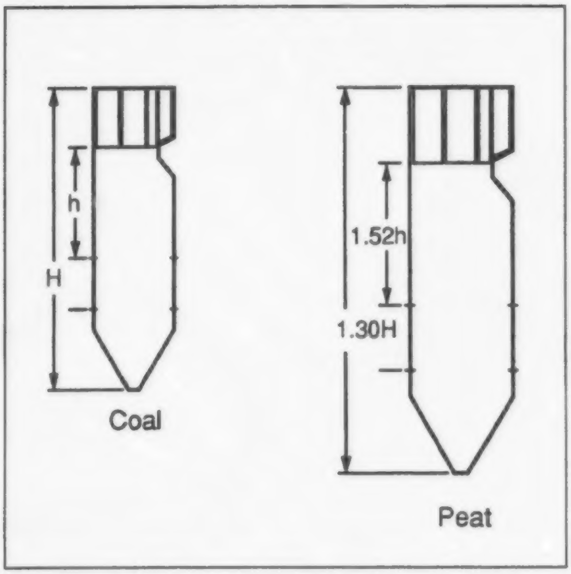
.7 Figure 5-3-1 illustrates the difference in physical size between peat and coal-fired boilers.

.8 In Finland and in Ireland many plants employ dual peat/oil burners, with an oil gun in the centre of the peat burner for ignition and flame stabilization.

.9 Peat-fired units are often designed to be co-fired with other fuels or multi-fired by a number of fuels depending upon availability; however, fuel changes can result in significantly different unit outputs.

.10 Particulate emissions are controlled by devices such as electrostatic precipitators, multicyclones, scrubbers or fabric filter baghouses.

*Figure 5-3-1: Comparison of Peat and Coal-Fired Boiler Sizes [J.G. Singer, 1981]*


h
H
Coal
1.52h
1.30H
Peat

### *Fuel Handling and Preparation: Dry-Mined Peat*

.11 The fuel handling and preparation systems at the generating station are significantly different from those required for a coal-fired plant.

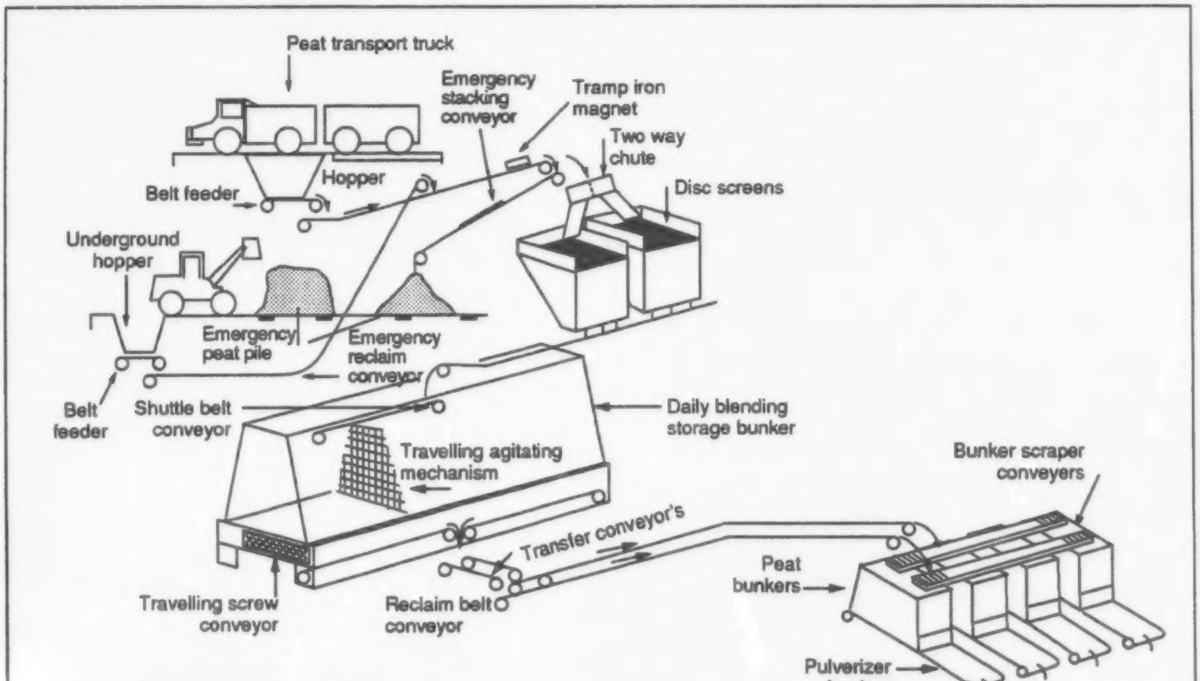
.12 In fuel form, milled peat is a light, powdery, abrasive and corrosive material which flows poorly.

.13 When milled peat is harvested from the bog it has a moisture content of about 50 percent and further dewatering before it is blown into a boiler is optional.

.14 It produces substantial fugitive dust emissions with the result that transport and handling systems must include dust controls and critical items are blanketed with inert gas to minimize fire hazard.

.15 Bogside stockpiles are often covered to control dust and to prevent the fuel from absorbing moisture from rain and snow.

*Figure 5-3-2: Fuel Handling System – Milled Peat-Fired Generating Station*


Peat transport truck
Emergency stacking conveyor
Tramp iron magnet
Two way chute
Hopper
Belt feeder
Disc screens
Underground hopper
Emergency peat pile
Emergency reclaim conveyor
Belt feeder
Shuttle belt conveyor
Daily blending storage bunker
Travelling agitating mechanism
Bunker scraper conveyers
Transfer conveyor's
Peat bunkers
Travelling screw conveyor
Reclaim belt conveyor
Pulverizer feeders

Source : Monenco Consultants Limited

.16 Stockpiles are subject to internal heating due to oxidation, and temperatures must be monitored to warn of localized heat generation which can lead to fire.

.17 Trucks take milled peat from bog-side stockpiles to the generating plant where the trucks are tipped to empty their loads into hoppers.

.18 Covered conveyors move peat from the hoppers through screens, lump crushers and magnetic separators to in-plant storage piles or to concrete blending bunkers as shown in Figure 5-3-2.

.19 In these large, expensive bunkers incoming fuel is spread in thin horizontal layers and reclaimed by a mechanism which takes vertical cuts starting from one side of the pile. This procedure results in a blended vertical cut.

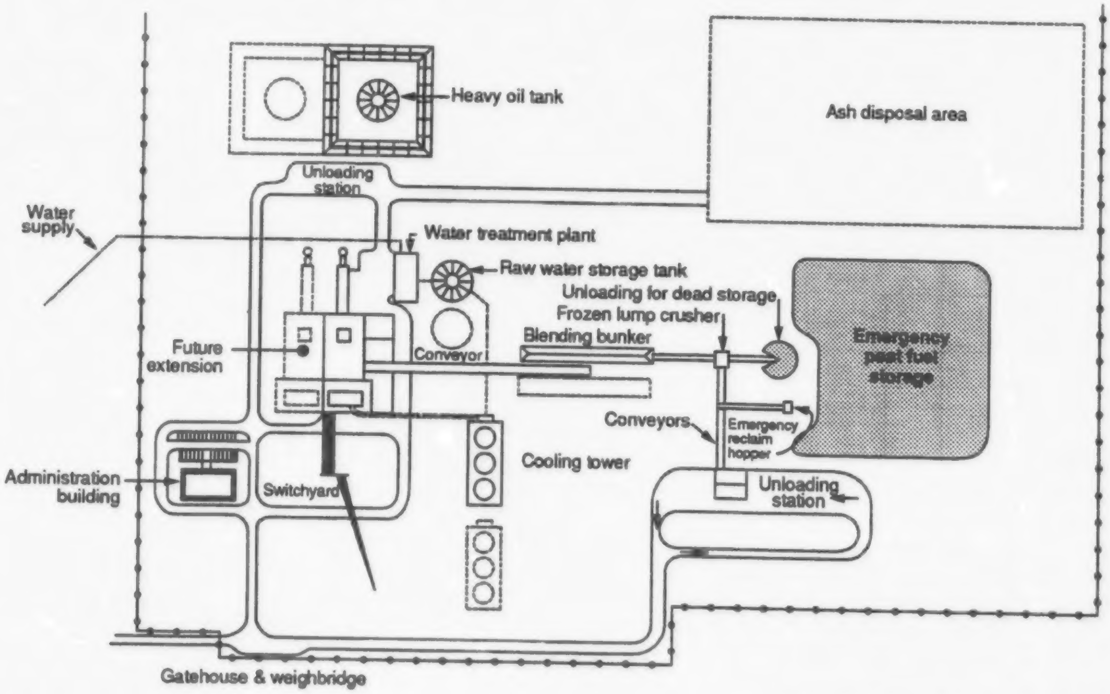
.20 Blending helps to even out large variations in moisture content of batches of milled peat delivered to the generating station, and enhances uniformity of fuel quality to the boiler.

.21 Figure 5-3-3, which illustrates a layout for a 40 MW, single unit, milled peat-fired power station, shows that the fuel is conveyed from the blending bunker to the boiler house bunkers.

.22 The delivery end of the boiler house bunker and the peat feeder are illustrated in Figure 5-3-4.

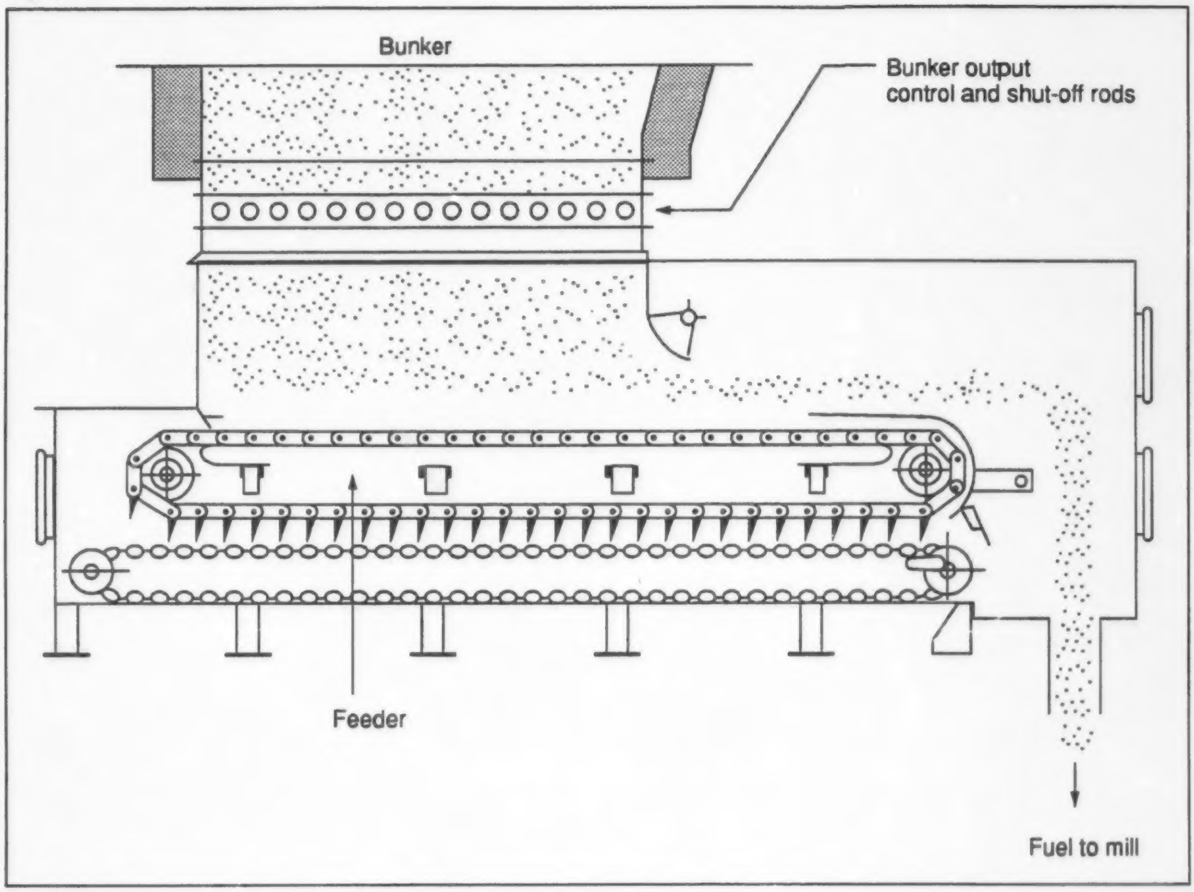
.23 Peat from the bunker is fed into pulverizers, called "hot gas suction pulverizers" because they use furnace gas to dry the peat as it is being pulverized by the beaters. The dried peat, its evaporated moisture and the furnace gas then enter the furnace, where the peat burns in suspension as a "pulverized fuel". A hot gas suction pulverizer is illustrated in Figure 5-3-5.

*Figure 5-3-3: Typical Site Layout –*
*1 x 40 MW Peat-Fired Generating Station*


Heavy oil tank
Ash disposal area
Unloading station
Water supply
Water treatment plant
Raw water storage tank
Unloading for dead storage
Frozen lump crusher
Blending bunker
Emergency peat fuel storage
Future extension
Conveyor
Conveyors
Emergency reclaim hopper
Cooling tower
Administration building
Switchyard
Unloading station
Gatehouse & weighbridge

Source : Monenco Consultants Limited

*Figure 5-3-4: Peat Bunker and Feeder*



.24 Figures 5-3-6 and 5-3-7 illustrate the layout and equipment of a typical 40 MW "conventional" milled peat-fired generating station.

.25 Recently designed systems divert hot flue gases for drying the fuel peat before it is fed to pulverizers, thereby improving both cost and unit efficiency by removing water vapour and exhausting it through the stack before the fuel enters the pulverizers. The boiler, its auxiliaries and the downstream air pollution control equipment can all be smaller and less expensive when they do not have to handle the water vapour.

.26 Peat fuel which has been dried by flue gases cannot be stored but must be burned immediately because of the high risk of spontaneous combustion.

.27 Sod peats are fired on grates in a manner similar to that described in Appendix B.

.28 In Finland 90 percent of all fuel peat in 1990 was milled peat. In Ireland 80 percent of all fuel peat in 1988 was milled peat.

.29 Sod peat may also be pulverized and may be thermally dried before being blown like milled peat into the boiler.

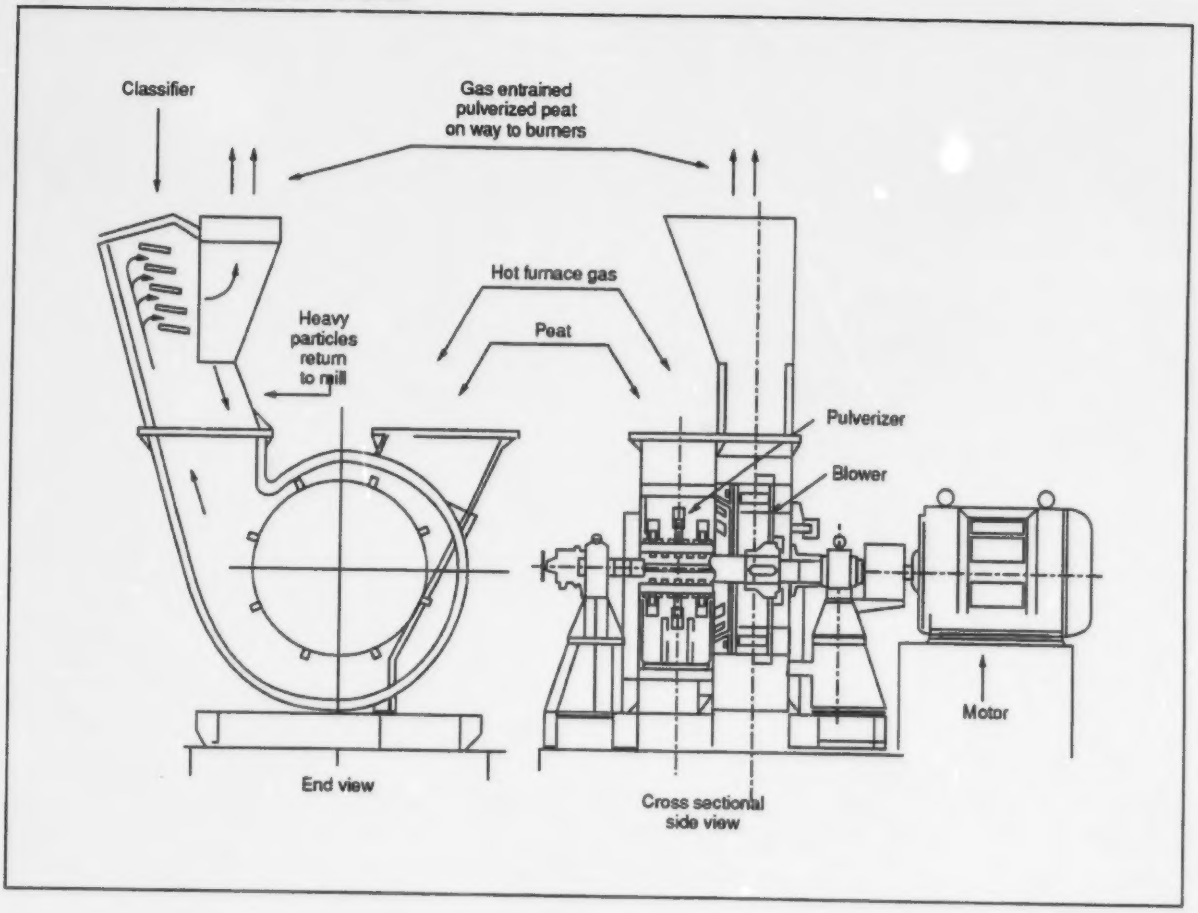
.30 Briquettes and peat pellets are normally too expensive for use in electricity generation.

### *Fuel Handling and Preparation: Wet-Mined Peat*

.31 Peat slurry at 90 to 95 percent moisture content is pumped from the bog to a dewatering plant.

.32 The first stage of slurry dewatering will involve a combination of mechanical systems such as centrifuging and filtration to produce a "filter cake".

***Figure 5-3-5: Hot Gas Suction Pulverizer***


Classifier
Gas entrained pulverized peat on way to burners
Hot furnace gas
Peat
Heavy particles return to mill
Pulverizer
Blower
Motor
End view
Cross sectional side view

.33 Since mechanical methods of dewatering raw peat can only partially remove free water, and have very little effect on bound water, the filter cakes are still at typically 75 percent moisture content. Further drying to 50 percent or lower must be effected by thermal evaporation. This is illustrated in Figure 5-2-13.

.34 A second method involves heating the peat slurry under pressure so the bound water in the micropores expands as steam and escapes its bonds. This is called thermal treatment of peat slurry, and the processes involved are identified in Figure 5-2-14.

.35 While raw peat slurries can be mechanically dewatered to 75 percent moisture content, tests show that thermally treated peat slurries can be mechanically dewatered to 50 percent moisture content.

.36 Filtrate from mechanical dewatering of peat is non-toxic and can be returned to the bog. However thermal treatment of a peat slurry, if that process is used, makes the filtrate toxic. In the latter case the filtrate requires complex and expensive treatment prior to disposal.

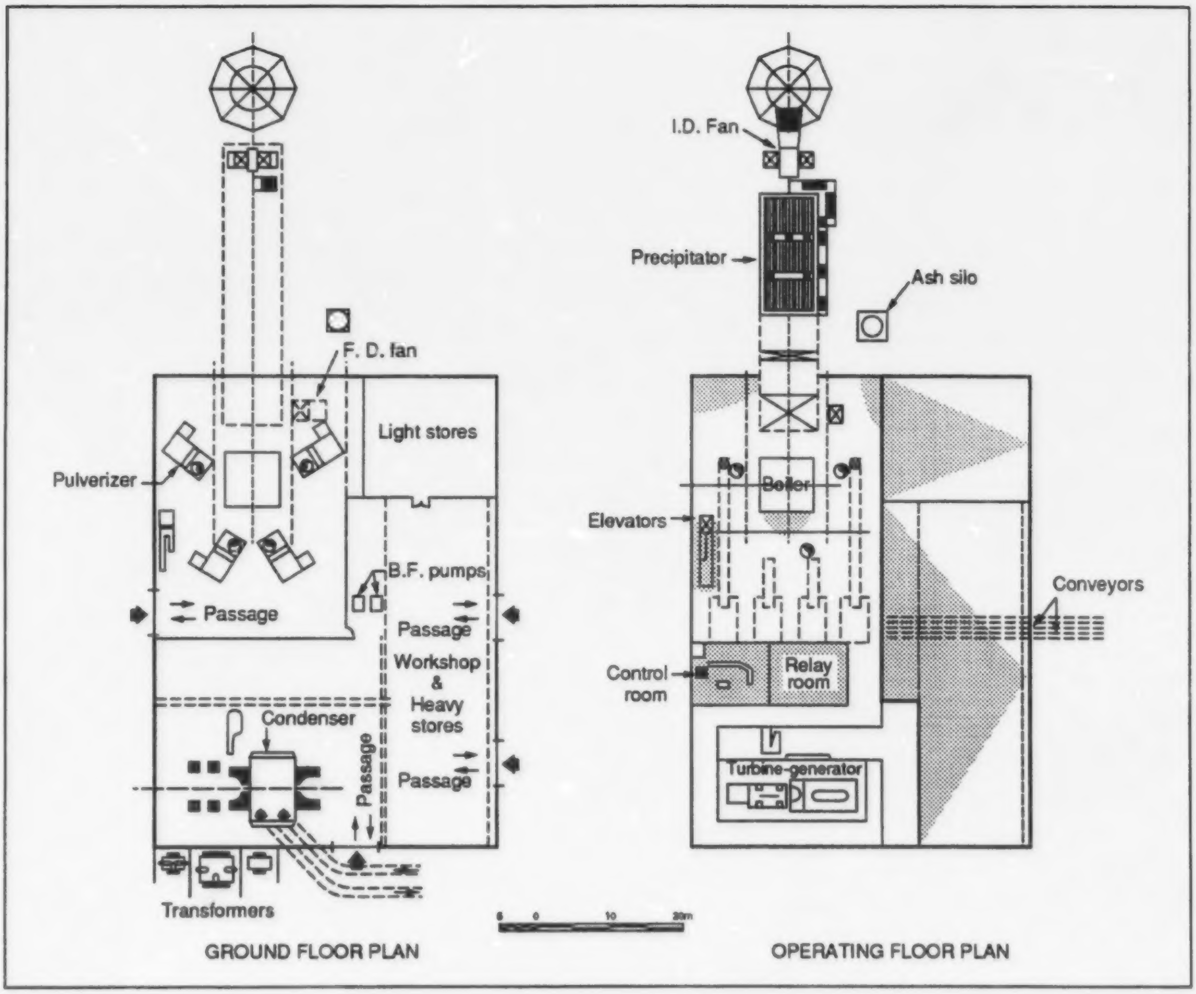
.37 Filter cake at 50 percent moisture content can be burned on a grate or in a fluidized bed or it can be pulverized and blown into a suspension-fired boiler.

## 5-4 Experience

### 5-4-1 World Experience

.1 Peat has traditionally been employed in some parts of the world for space and process heating as well as for the manufacture of process feedstocks.

***Figure 5-3-6: 1 x 40 MW Peat-Fuelled Power Plant – Floor Plan Layouts [Monenco Consultants Limited]***


F. D. fan
Light stores
Pulverizer
B.F. pumps
Passage
Passage
Workshop & Heavy stores
Condenser
Passage
Passage
Transformers
GROUND FLOOR PLAN
I.D. Fan
Precipitator
Ash silo
Boiler
Elevators
Conveyors
Control room
Relay room
Turbine-generator
OPERATING FLOOR PLAN
5 0 10 20m

.2 In this century, peat has been used as a fuel for electricity generation.

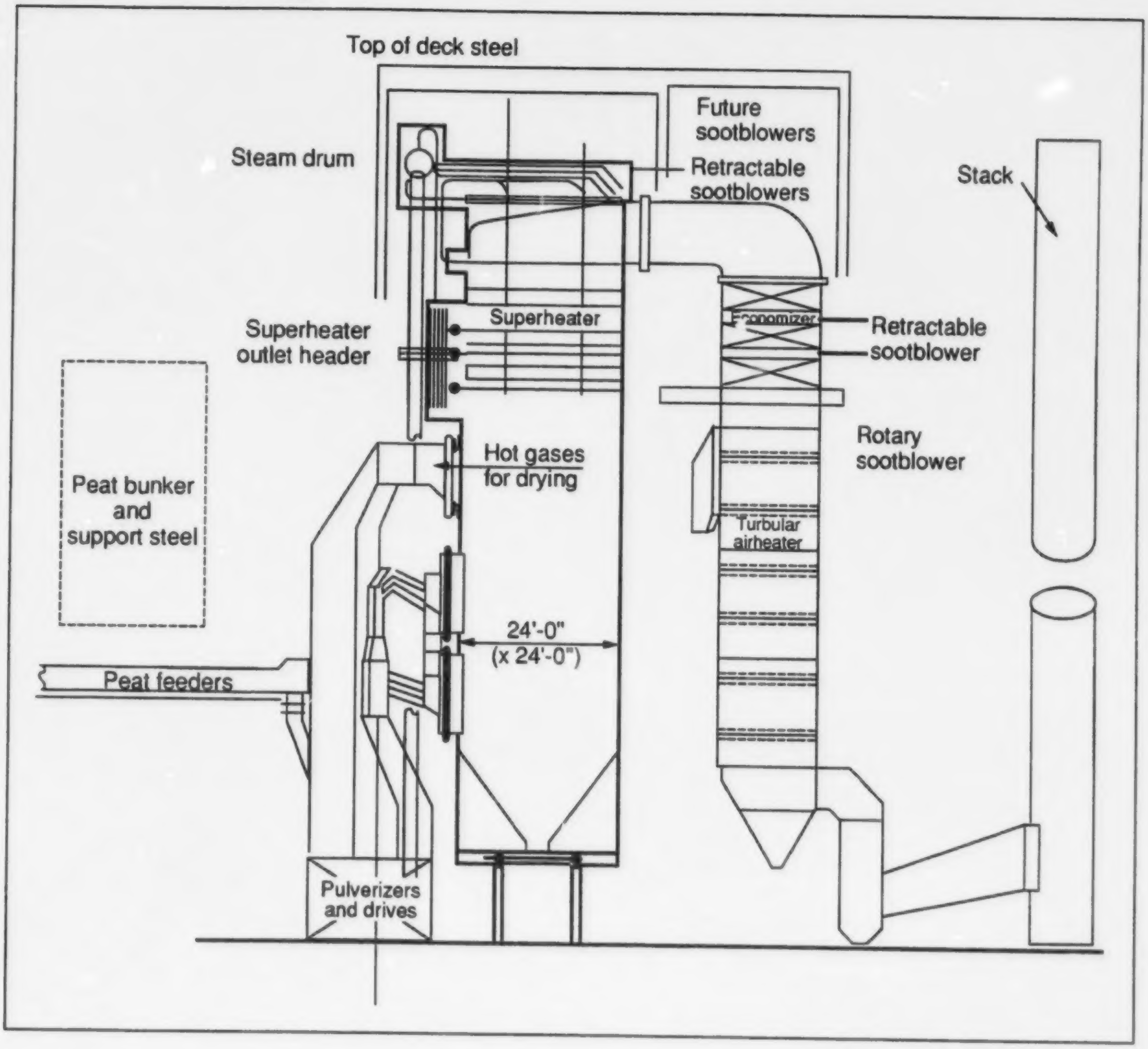
.3 Peat-fired thermal plants exist in Ireland, Finland, Sweden and the U.S.S.R. The industry appears to be most highly developed in Finland and Ireland.

.4 There may be as much as 1,000 MW of peat-fired generation in the U.S.S.R., where three-unit stations possibly as large as 360 MW are reported to be operating; however, there is very little information available about the size and performance of those plants.

.5 Ireland produces about 500 MW of electricity from peat. Irish stations are mainly electricity generating rather than cogenerating stations.

.6 Since the 1970s, Finland has turned increasingly to peat for electricity generation, usually in conjunction with process or district heating, and frequently by co-firing peat with other biomass fuels, coal or oil.

***Figure 5-3-7: 1 x 40 MW Peat-Fuelled Power Plant – Boiler [Monenco Consultants Limited]***


Top of deck steel
Steam drum
Future sootblowers
Retractable sootblowers
Stack
Superheater
Superheater outlet header
Economizer
Retractable sootblower
Rotary sootblower
Hot gases for drying
Peat bunker and support steel
Turbular airheater
24'-0" (x 24'-0")
Peat feeders
Pulverizers and drives

.7 Figure 5-4-1 contains a partial list of Finnish peat-fired power plants as of 1988. Those stations produce about 600 MW. Most Finnish peat firing is for cogeneration of electricity and heat. Since 1988, additional capacity has been added, including larger units of up to 150 MW electrical capacity.

.8 Finnish peat technology is well developed and Finnish companies offer equipment and services around the world.

.9 Pulverized fuel firing is the "conventional" utility method of power generation from milled peat, which forms the bulk of the peat fuel used in Finland and Ireland.

.10 At the present time there are no peat fuels produced by wet mining or slurried peat systems because dry mining is a suitable technology for Finnish and Irish conditions.

*Figure 5-4-1: Partial List of Peat-Fired Power Stations in Finland*

| Name of Station | Type of Peat | MWe | MWt |
|---|---|---|---|
| Electricity Generation (Ind. Cogen.) | | | |
| Ahlstrom Oy/Kauttua | milled | 16.6 | – |
| Kemira Oy/Oulu | " | 10.8 | – |
| Kemira Oy/Valkeakoski | " | 12.2 | – |
| Metsa-Serla Oy/Kuopio | " | 20 | – |
| Rosenlew Oy/Pori | " | 24 | – |
| Tampella Oy/Heinola | " | 18.7 | – |
| Yhtyneet Paperitehtaat/Jamsankoski | " | 23.5 | – |
| Yhtyneet Paperitehtaat/Simpele | " | 18.3 | – |
| Combined District Heat/Power | | | |
| Kuopion EL/Haapaniemi 1 | milled | 98 | 179 |
| Oulun kaupungin SL | " | 74.6 | 145 |
| Tampereen kaupungin SL/Naistenlahti 1 | " | 63 | 230 |
| Tampereen kaupungin SL/Naistenlahti 2 | " | 65 | |
| Imatran Voima Oy/Joensuu | " | 76 | 120 |
| Imatran Voima Oy/Rauhalahti | " | 82.5 | |
| **Total** | | 603.4 | 834 |

## 5-4-2 Canadian Experience

.1 There are no peat-fired generating stations in Canada.

.2 Canadian companies and researchers have harvesting experience associated with horticultural peat.

.3 In part that experience results from horticultural uses of peat, and in part, from work undertaken by Energy, Mines and Resources (EM&R) Canada, by the National Research Council Canada and Monenco Consultants Limited in the period of high oil prices, roughly 1975 to 1985.

.4 Ontario Hydro has no direct experience with peat-fired generation.

## 5-5 Potential System Application

.1 Peat-fired generating stations are dispatchable and could be operated to meet base and intermediate loads.

.2 For economic and technical reasons (frequent start-ups and shut-downs would be undesirable), peat plants would likely be run as much as possible, hence are best suited to loaded operation.

.3 Pulverized milled peat-fired plants are capable of limited load following.

.4 Since peat-fired plants are often utilized in cogeneration applications, considerations regarding the process/plant which uses the heat may override considerations about the time/frequency at which power would be supplied to an electrical grid.

.5 For economic reasons, peat plants are best located near the source of fuel. This factor could potentially limit the size of the plant and/or the frequency with which it would be used for electricity generation, depending on the ability of the local grid to accept the power.

## 5-6 Environmental Considerations

.1 This section discusses environmental considerations, both natural and social, associated with the production of electricity from the burning of peat.

.2 Since peat fuel in forms other than slurry would likely be purchased in much the same fashion as other fossil fuels, it is assumed, for the purposes of this report, that environmental considerations associated with the extraction and processing of those fuels would be dealt with by the suppliers.

### 5-6-1 Natural Environment

.1 This section discusses environmental and safety issues associated with peat technologies and their impact on the natural environment, under the headings of air, land, water and other.

.2 Peat-fired generating stations would produce:

- fugitive dust emissions,
- leachates from fuel storage piles,
- oxides of sulphur ($SO_x$),
- oxides of nitrogen ($NO_x$),
- trace organics,
- carbon dioxide ($CO_2$),
- carbon monoxide (CO), and
- bottom ash and fly ash.

.3 Pollution control technologies used at coal and oil-fired generating stations are applicable to peat-fired generation.

*Air*

.4 Peat contains low concentrations of sulphur and when burned produces relatively low $SO_x$ emissions per kWh.

.5 $NO_x$ emissions from the combustion of peat per unit of electricity generated are comparable to, or slightly higher than, those from fossil fuels because of the lower efficiency of peat-fired generation.

.6 Fluidized bed combustion systems and specialized burners can be used to reduce $NO_x$ emissions.

.7 $SO_x$ and $NO_x$ emissions can be controlled to satisfy existing and proposed federal guidelines and provincial regulations.

.8 Particulate emissions from the combustion of peat can, as those from coal, be effectively reduced to meet regulatory requirements, using methods described in Appendix B.

.9 Unburned hydrocarbon (e.g., VOCs and PAHs) and carbon monoxide emissions result from incomplete combustion. These emissions can be mitigated by good boiler design and well controlled operation. Experience in Finland indicates that emissions of some hydrocarbons (PAHs) are comparable for peat and coal-fired facilities. (Tibbetts, 1986)

.10 Carbon dioxide emission is common to all fossil-fuelled power generation. $CO_2$ emissions are, however, approximately 30 percent higher than those from a coal-fired plant of equivalent capacity. There is no commercially available method for removing $CO_2$ emissions from flue gas.

.11 Dust emissions from peat piles and fuel and ash handling systems are expected to be controlled by covering or other means, in accordance with regulations.

*Land*

.12 The peatland ecosystem undergoing mining/extraction would be disrupted.

.13 Alternate uses for mined peatlands include creation of new lakes, ponds, reforested areas (e.g., biomass plantations) and farmland, depending on the method of mining used.

.14 On-site facilities for a peat-fired generating station of 75 MW would occupy approximately 35 to 50 hectares.

.15 About 5000 hectares of peatland (50 square kilometres), three metres deep, would be required to operate that station for 30 years at about 80 percent ACF.

.16 Peat and coal generate approximately the same amount of ash per tonne of dry fuel. Since the energy density of peat is about 70 percent of coal, and its generation efficiency is around 75 percent of coal, the ash generated per kwh of generation from peat firing is about twice that from coal firing.

.17 In the case of peat-firing, bottom ash and fly ash may have to be disposed of in engineered landfills or lagoons.

*Water*

.18 Filtrate from mechanical dewatering of peat is non-toxic and can be returned to the bog. However thermal treatment of a peat slurry, if that process is used, produces a filtrate that would require treatment prior to disposal.

.19 Peat fuel pile and ash leachates must be managed in accordance with applicable regulations.

.20 Cooling water requirements for peat-fired plants would be comparable to or somewhat higher than equivalent fossil-fired facilities. In Finland, most peat-fired stations also provide district or process heating, thereby making better use of the energy content of the fuel and lesser use of cooling water.

*Other*

.21 Noise emissions from a peat-fired generating station would be comparable to those from a coal-fired facility.

.22 In-plant fugitive dust must be controlled, as in coal-fired plants, to minimize the risk of explosion and fire.

.23 Peat fuel piles must be managed and monitored to prevent the occurrence of spontaneous combustion.

### 5-6-2 Social Environment

.1 This section discusses issues associated with peat technologies and their impact on the social environment, under the headings of socio-economic effects and societal considerations.

*Socio-Economic Effects*

.2 Peat-fuelled generating facilities would likely be situated in northern or eastern Ontario. In such instances, peat-fuelled facilities could provide local economic stimulus.

.3 Positive long-term employment benefits may be offset, however, by the seasonal nature of the peat workforce. Dry mining may result in regional and local employment impacts such as the immigration of seasonal workforces to small communities and associated demands on community facilities and services.

.4 The potential also exists for localized community impacts (e.g., increased access, traffic) during construction, operations and decomissioning activities because of the centralized nature of a peat-fuelled facility.

.5 Peat operations have the potential to create additional local community impacts (e.g., dust, noise and odours) which may result in social acceptance concerns.

.6 Additional local services may be required due to the need for dust and fire suppression on and off-site. Requirements for ash disposal may result in additional social economic concerns.

*Societal Considerations*

.7 Peatland growth has been estimated to take place at about 1 mm/year in northern climates. Peat cannot be considered a renewable or carbon dioxide neutral resource. Ecosystem disruption may also occur. For these reasons, it has a potential for significant social concerns. However, harvesting of peat for horticultural and fuel uses is an accepted practice in a number of countries.

## 5-7 Operational Considerations

### 5-7-1 Maintenance

.1 Peat-fuelled power plants would require on-going, on-line preventive maintenance throughout the year in accordance with a preventative maintenance schedule based on supplier specifications and good power plant practice.

.2 These plants would likely be shut down for a period of two weeks each year, probably in summer, for annual off-line maintenance, cleanout and repair of such equipment as cannot be accessed on-line, such as internals of the boiler, draft system and air pollution control equipment. Maintenance inspection or repair which can only be done during downtime would be carried out during this annual shutdown of the plant. A major overhaul would be scheduled every five to seven years.

### 5-7-2 Staffing

.1 These plants would be staffed by a superintendent or chief station engineer and a certified stationary engineer during each shift. Staffing levels for peat-fuelled stations would be somewhat higher than those for coal-fuelled stations of the same capacity.

### 5-7-3 System Life

.1 Peat-fuelled power plants are assumed to have a 30 year life, given adequate maintenance, interim repair, replacement and major overhauls.

### 5-8 Development Issues

.1 A prerequisite for peat-fired power generation in Ontario is the development of an economically priced peat fuel.

.2 Conventional milled peat-fired stations are expensive because of complex fuel handling and pulverizing technology. Hence, the cost of power from peat is not competitive with large fossil-fuelled generating stations in Ontario.

.3 Although fluidized bed combustion of peat is gaining ground in Finland, the most modern and largest peat-fired power stations (commissioned 1990) still use conventional milled peat firing. Conventional combustion technology may therefore continue to dominate peat-fired power generation for some years.

.4 Since dry mining may not prove suitable for Ontario's climate and demographic regimes, wet mining slurry preparation and pumping, slurry dewatering and peat fuel preparation technologies may have to be developed.

.5 Along with fuel preparation systems based on wet mining, it would be necessary to investigate related land reclamation and utilization of excavated peat bogs in relation to the stability of ecosystems and environmental sustainability.

.6 The possibility of foresting excavated peatland for use as energy plantations could be investigated. Currently large tracts of Ontario wetland lie in their virgin state. They constitute habitat for many wildlife and micro-organic species which must be preserved. However, since the majority of Ontario's wetland areas (particularly those containing shallow, small and discontinuous bogs) are unlikely to be mined for resource, there is little danger of total loss of any species.

### 5-9 Options Selected for Costing

.1 The size of a peat-fired boiler plant would be determined by the availability of the fuel, over the life of the plant, from bogs within economic transportation distance of the plant.

.2 The largest single unit for Ontario's type of resources is likely to be about 75 MW.

.3 Based on the constraints discussed above, and on the nature of peat power generation technologies, plants would normally be composed of one or two small units, probably in the order of 5 to 40 MW each.

.4 These plants would need to be located close to peat resource areas. If, at the selected location, water supply for coolant systems is limited, then wet or dry air cooling systems could be used.

.5 An annual capacity factor of 80 percent is currently estimated during the 30 year life of the plant. It may improve to 85 percent with standardization of design, construction and operation, based on experience.

.6 The plant design is based on pulverized fuel firing of milled peat at nominal 50 percent moisture content in the fuel.

.7 The majority of units in Finland and Ireland are smaller than 40 MW.

.8 The largest single unit (a recently commissioned generating station at Haapavesi in Finland) has a nominal rating of 150 MW.

.9 Since Ontario bogs are generally more shallow, and individual bogs generally have smaller areas, than Finnish and Irish bogs, it has been assumed that the largest individual unit foreseeable in Ontario would be approximately 75 MW.

.10 Based upon these considerations two pulverized peat fuel power generation options have been selected for costing – a 15 MW option at the lower end, and a 75 MW option at the upper end.

.11 The station net heat rate at full load is expected to range from 13,850 kJ/kWh for the 15 MW unit to 13,570 kJ/kWh for the 75 MW unit. These values correspond to overall station efficiencies of 26 and 26.5 percent, respectively.

### 5-9-1 Peat Option 1: 1 x 15 MW Peat-Fuelled Station

.1 The technology for this option is based on a conventional pulverized peat steam-electric cycle. The technology is fully proven in Finland and Ireland.

.2 Special equipment, such as fuel handling equipment, boilers and pulverizers can be supplied by Canadian companies on the basis of established and proven design from their European affiliates.

.3 Air pollution control equipment would be standard, as for coal fired stations, because peat contains about the same percentage of ash as does coal.

.4 Turbine generator and auxiliaries, and all balance of plant would be the same as for a fossil-fuelled station of similar capacity.

.5 Whenever possible, the station would be designed as a cogeneration unit, so as to optimize fuel conversion efficiency and economic viability.

.6 The economics of incorporating a flue gas fuel drying system should be reviewed at the design stage, but this feature has not been incorporated in this review.

.7 The station would be operated as a base-loaded station for economic and technical reasons. However the pulverized fuel-fired system will be capable of operating as a medium load unit. The station would operate at an average of 80 percent ACF and provide power to the bulk electricity system grid.

.8 It is expected that light oil or natural gas will be an auxiliary fuel for ignition and for flame stabilization at low loads.

### 5-9-2 Peat Option 2: 1 x 75 MW Peat-Fuelled Station

.1 The specification for this station is the same as for Option 1. The only difference is size and rating of plant equipment.

.2 These larger units provide more power at a lower capital cost in dollars per MW.

## 5-10 Costs and Performance

.1 This section discusses the performance and cost assumptions used to estimate the levelized unit energy costs for the 15 MW and 75 MW peat-fuelled options considered.

### 5-10-1 Performance Assumptions

.1 Figure 5-10-1 summarizes the performance assumptions used in evaluating the levelized unit energy cost of the peat-fuelled options.

.2 Both options are assumed be to fuelled with milled peat.

### 5-10-2 Cost Estimates

.1 Ontario Hydro has no experience with the design, construction, installation and operation of peat-fuelled power plants.

*Figure 5-10-1: Peat Performance Assumptions*

| Option | Description | Useful Life (yrs.) | Annual Capacity Factor (%) | Thermal Efficiency (%) |
|---|---|---|---|---|
| 1 | 15 MW Conventional Thermal | 30 | 80 | 26.0 |
| 2 | 75 MW Conventional Thermal | 30 | 80 | 26.5 |

.2 The cost estimates are developed based mainly on reports commissioned by Ontario Hydro and prepared by experts in the field. Cost estimates are based on the most current information available to Ontario Hydro, and are not site specific. The costs are intended to provide an indication of a range of costs and not a definitive estimate of the cost of each option.

.3 The cost estimates presented are current (1991) costs.

.4 The costs presented are those for electricity as the only product. Section 5-10-5 shows the potential value of the useable heat from the two peat-fuelled options, given the assumptions about the amount and value of the heat discussed in Part 1, Section 1-7.

.5 Capital, OM&A and Fuel cost estimates for the peat-fuelled options are shown in Figure 5-10-2.

*Figure 5-10-2: Cost Estimates – Peat-Fuelled Options*

| Cost Component | 15 MW Plant (Current Costs) | 75 MW Plant (Current Costs) |
|---|---|---|
| Initial Capital ($/kW) | 6,224 | 2,719 |
| Later Capital ($/kW/yr) | 31 | 14 |
| OM&A ($/kW/yr) | 253 | 119 |
| Fuel (¢/kWh) | 6.8 | 6.4 |

### 5-10-3 Levelized Unit Energy Cost Summary

.1 The levelized unit energy costs obtained using the performance and cost estimates shown above are summarized in Figure 5-10-3 for the peat-fuelled options.

### 5-10-4 Sensitivity Ranges

.1 For each option, the sensitivities of the levelized unit energy cost to variations in the values of the individual cost components, in economic factors and in performance, are presented. Sensitivity analyses provide an indication of the variability of the levelized unit energy cost to changes in cost and performance assumptions.

*Figure 5-10-3: Levelized Unit Energy Cost Estimates – Peat-Fuelled Options*

| Levelized Unit Energy Cost (LUEC) Estimates at 80% ACF (¢/kWh) | | |
|---|---|---|
| Cost Component | 15 MW Plant (Current Costs) | 75 MW Plant (Current Costs) |
| Total Capital | 8.0 | 3.5 |
| OM&A | 4.8 | 2.2 |
| Fuel | 6.7 | 6.5 |
| Total LUEC | 19.5 | 12.2 |

.2 The cost estimates for peat-fuelled power plants are subject to large uncertainties. These large uncertainties are reflected in the sensitivity ranges chosen.

.3 The sensitivity ranges selected are not intended to reflect a particular confidence level. The level of information available does not lend itself to such a detailed analysis. They simply represent Ontario Hydro's judgement on the possible variation of these factors.

.4 Figures 5-10-4 and 5-10-5 show the sensitivity ranges selected for costs and performance respectively, and the effect of those ranges on the levelized unit energy costs for the two options assessed.

.5 Given the assumptions in this report regarding costs and performance, the largest range of levelized unit energy costs for each option can be obtained by assuming that all cost components and performance factors are fully dependent. That is, if one cost component increases, all cost components are assumed to increase and all performance factors are assumed to decrease, and vice-versa. In this manner, an indication of the upper and lower ranges of the levelized unit energy costs for each option is obtained. These upper and lower estimates are shown in Figure 5-10-6.

### 5-10-5 Potential Value of Useable Heat

.1 The economic evaluations shown above consider electricity as the only product. Peat-fuelled power plants may often be installed in cogeneration applications producing both electricity and useable heat. Revenues from the use or sale of heat could partially offset electricity production costs.

*Figure 5-10-4: Cost Component Sensitivity – Peat-Fuelled Option*

| Cost Component | LUEC at 80% ACF (¢/kWh) | Range Assumed (%) | | Sensitivity (%) * | |
|---|---|---|---|---|---|
| | | Lower | Upper | Lower | Upper |
| **Option 1 – 15 MW** | | | | | |
| Capital | 8.0 | -20 | +20 | -8.2 | +8.2 |
| OM&A | 4.8 | -10 | +15 | -2.5 | +3.7 |
| Fuel | 6.7 | -33 | +45 | -11.3 | +15.4 |
| Total | 19.5 | | | -22.0 (1) | +27.3 (1) |
| **Option 2 – 75 MW** | | | | | |
| Capital | 3.5 | -20 | +20 | -5.7 | +5.7 |
| OM&A | 2.2 | -10 | +15 | -1.8 | +2.7 |
| Fuel | 6.5 | -33 | +45 | -17.6 | +24.0 |
| Total | 12.2 | | | -25.1 (1) | +32.4 (1) |

* Percentage change in total LUEC of each option.

(1) Total sensitivities are calculated assuming all cost components are fully dependent.

*Figure 5-10-5: Performance Sensitivities – Peat-Fuelled Options*

| Factor | Point Estimate | Range Assumed | | Sensitivity (%) * | |
|---|---|---|---|---|---|
| | | Lower | Upper | Lower | Upper |
| **Option 1 – 15 MW** | | | | | |
| Annual Capacity Factor | 80% | 90% | 60% | -6.8 | +22.4 |
| Life (years) | 30 | 35 | 25 | -1.6 | +2.6 |
| Thermal Efficiency | 26.0% | 27.0% | 25.0% | -1.2 | +1.4 |
| **Option 2 – 75 MW** | | | | | |
| Annual Capacity Factor | 80% | 90% | 60% | -4.5 | +13.4 |
| Life (years) | 30 | 35 | 25 | -1.1 | +1.9 |
| Thermal Efficiency | 26.5% | 27.5% | 27.5% | -1.8 | +2.1 |

* Percentage change in total LUEC of each option.

.2 The heat is valued on the basis of Ontario Hydro's forecast of the industrial direct price of natural gas. In addition, as discussed in Part 1, Section 1-7, it is assumed that 80 percent of the energy content of the fuel is recovered in a cogeneration application as electricity and useable heat.

.3 In this analysis it is also assumed that no additional costs would be incurred for the installation and operation of heat recovery and distribution equipment.

.4 The potential value of the useable heat produced, expressed as a levelized unit energy benefit (LUEB), is estimated to be 3.8 ¢/kWh for Option 1 and 3.7 ¢/kWh for Option 2.

### 5-10-6 Cost Summary

.1 The results in Figure 5-10-6 show that the current levelized unit energy costs of electricity from peat-fuelled power plants range from a lower estimate of 9.4 ¢/kWh to a higher estimate of 29.0 ¢/kWh. These costs are too high to make electricity production from peat-fuelled power plants currently economic as a source of generation for the bulk electricity system in Ontario, given that the levelized unit energy costs of conventional base-loaded generation options (for example, nuclear or conventional steam cycle coal) are projected to be in the range of 3 to 5 ¢/kwh.

*Figure 5-10-6: Overall Sensitivity – Peat-Fuelled Options (All Factors Fully Dependent)*

| Option | Overall Sensitivity – LUEC (¢/kWh) | | |
|---|---|---|---|
| | Lower Estimate | Point Estimate | Upper Estimate |
| Option 1 – 15 MW | 14.5 | 19.5 | 29.0 |
| Option 2 – 75 MW | 9.4 | 12.2 | 17.2 |

.2 The use of peat-fuelled power plants in combined heat and power applications would make these plants more economical since revenues from the use of or sale of heat could partially offset electricity production costs.

## 5-11 Potential

### 5-11-1 Scenario Descriptions

.1 The potential for peat-fuelled power plants is assessed under the three scenarios described earlier in Part 1, Section 1-8. These scenario descriptions are repeated below.

*Scenario 1:* In this scenario, it is assumed that there is no improvement in current costs and technological status by the year 2000. The potential contribution by the year 2005 is assessed.

*Scenario 2:* In this scenario, an attempt is made to account for cost and technological improvements which may occur by the year 2000. Given these improvements, the potential contribution by the year 2005 is reassessed.

*Scenario 3:* The projections in this highly speculative scenario are based on assumptions that significant improvements in technology and costs could occur by the year 2010. The potential contribution by the year 2014 is assessed.

### 5-11-2 Assumptions and Conditions

*Peat Fuel*

.1 Currently most peat fuel production is based on dry mining, and the cost of milled peat (at 50 percent moisture content) is estimated at around $4 per gigajoule (GJ). Development work is under way in many countries, including Canada, to find ways of producing peat fuel at around $2 per gigajoule or less. Some Canadian developers claim success in this area but, as far as is known, have not demonstrated production at this cost on any commercial scale.

.2 Wet mining and slurry dewatering technology is an area of development which may favour production of peat fuel at reduced cost under Canadian conditions.

.3 Scenario 1 assumes that high peat fuel costs will deter development of peat-fuelled electrical generation.

.4 Scenario 2 assumes that at least one of the alternative peat fuel production technologies will be demonstrated by year 2000, and may successfully prove that peat fuel can be marketed at $2 per gigajoule or less.

.5 Scenario 3 assumes that the above peat fuel technology will be commercially available.

*Technology*

.6 Conventional milled peat firing technology involves high capital and OM&A costs and operates at an efficiency of around 25 percent. Considerable development work is under way in Canada and abroad to develop and demonstrate peat IGCC systems (frequently involving the use of fluidized bed or fixed bed gasifiers). These developments have the following objectives:

- increasing electrical generation efficiency from around 25 percent to as much as 40 percent, and
- reducing capital and OM&A costs.

.7 Scenario 1 assumes conventional peat firing technology.

.8 Scenario 2 assumes that both cost-effective peat fuel production technology and peat IGCC technology will be in demonstration phase by year 2000.

.9 Scenario 3 assumes that both cost-effective peat fuel production technology and peat IGCC technology will be commercially available by the year 2010.

### 5-11-3 Projections of Potential

.1 The above assumptions lead to the following projections of capacity for peat-fuelled generation under the three scenarios described above:

| | Peat-Fuelled Generation |
|---|---|
| Scenario 1 | Nil |
| Scenario 2 | 20 MW |
| Scenario 3 | 100 MW |

.2 The projections in Scenarios 3 are considered reasonable on the basis that peat-fuelled electrical generation requires large wetland areas to be exploited. Demonstration and commercialization of such technology is time consuming, as is resource assessment. Further complex ecological, environmental, and land reclamation and re-use issues are likely to be involved. Should all these issues be resolved it would then take considerable time to drain the peat bogs and commence peat fuel production. The timing of peat-fuelled generation facilities must therefore correspond with a complex schedule and sequence of key events.

.3 Figure 5-11-1 summarizes the above assumptions and projections.

### 5-12 Overall Assessment

.1 Peat is a significant resource indigenous to Ontario.

.2 Peat has been used extensively as a fuel for electricity generation in Ireland and Finland, sometimes co-fired with other fuels such as wood and coal. Milled peat is the most common form of the fuel. The technology for the dry mining of peat is proven.

*Figure 5-11-1: Forecast of Potential Contribution of Peat*

| Scenario | Assumptions | Major Factors Affecting Potential | Cost Compared to Conventional Generation | Potential | | Potential Applications |
|---|---|---|---|---|---|---|
| | | | | MW | By Year | |
| 1 | • Current costs.<br>• Current technology (conventional milled peat technology).<br>• Current financial incentives.<br>• Milled peat fuel cost around $4/GJ. | • High capital cost.<br>• Low efficiency.<br>• Price of peat fuel.<br>• Dependent on financial incentives. | Above | NIL | 2005 | |
| 2 | • Improved mining technology reduces fuel cost to $2/GJ.<br>• Demonstration peat IGCC technology.<br>• Current financial incentives.<br>• Demonstration peatland reclamation. | • High capital cost of plant.<br>• Price of fuel. | Above | 20 | 2005 | • Demonstration of peat fuel production and peat IGCC technologies. |
| 3 | • Proven mining technology.<br>• Proven peat IGCC technology.<br>• Proven peatland reclamation.<br>• Peal fuel at $2/GJ.<br>• Current financial incentives. | • Combination of favourable factors assumed will reduce cost of peat-fuelled electricity. | Marginally above | 100 | 2014 | • Utility/NUG/ cogen/co-firing. |

.3 The use of peat in North America has been, and continues to be, mainly horticultural.

.4 In the late 1970s and early 1980s there was considerable interest in peat-firing in Canada due to the high cost of oil. Since oil prices have dropped, much of the interest in the use of Canadian peat has declined. Peat remains a less economic fuel than oil, gas and coal.

.5 In 1986 the National Research Council reported that as an energy commodity the short and medium-term prospects for peat were not encouraging. Energy related considerations have not changed significantly since that time.

.6 Cost is a major factor limiting the replacement of fossil fuels by peat. Peat is more costly than oil, gas and coal because of its lower energy density and high cost of dewatering. Peat-fuelled plants are physically larger, and of higher capital costs, than fossil-fuelled plants of equivalent capacity.

.7 This review estimates that the current levelized unit energy cost (LUEC) of electricity produced by peat power plants fuelled with milled peat will be in the range of 9.4 ¢/kWh to 29.0 ¢/kWh. These costs indicate that peat-fuelled power plants are not currently economic for the production of electricity for the bulk electricity system in Ontario.

.8 Ontario peat is a very dispersed resource. Vast areas of bog are either altogether inaccessible, or contain very shallow deposits of peat which are uneconomic for mining, or the bogs cannot be drained for dry mining purposes. A few such areas could be mined if cost-effective wet-mining and slurry dewatering technologies are successfully developed.

.9 If Ontario's peat fuel resources are to be developed, wet mining techniques may prove more cost-effective for small separated bogs and are less dependent on seasonal climatic conditions.

.10 Peat-fuelled generating stations would have to be located close to the source of the peat to avoid prohibitive transportation costs.

.11 Peat burning produces lower $SO_2$ emissions than does coal combustion. $CO_2$ emissions are, however, approximately 30 percent higher than those from a coal-fired plant of equivalent capacity. Possible environmental concerns associated with peat extraction would need to be addressed.

.12 Ontario's peat deposits are located primarily in the northern and southeastern parts of the province and they cover some 16 million hectares. If less than 2 percent of those peat resources were used they could potentially support about 5000 MW of generating capacity over 30 years. As discussed in Section 5-11, the potential contribution of peat-fuelled power plants to Ontario's electricity supply mix could be in the order of 20 MW by the year 2005 and as high as 100 MW by the year 2014.

.13 Peat-fuelled generating facilities would likely be situated in northern or eastern Ontario. In such instances, peat-fuelled facilities could provide local economic stimulus. However, in the case of dry mining, positive long term employment benefits may be offset by the seasonal nature of the peat workforce. The potential exists for localized community impacts (e.g., increased access, traffic, dust, odour and noise) during construction or operations activities. Significant social concerns may also exist regarding non-renewability, ecosystem disruption and $CO_2$ emissions.

.14 Advantages of peat as a fuel for electricity generation include:

- indigenous fuel, and
- low sulphur dioxide emissions.

.15 Barriers to wide-scale introduction of peat-fuelled electricity generation in Ontario include:

- high cost of fuel production and transportation,
- high capital cost of the generating plant, and
- possible environmental concerns about peat extraction and fuel preparation, $CO_2$ emissions and non-renewability.

## 5-13 References

Ontario Hydro, February 1989, **Alternative Energy Study – Peat,** A. Ismail/Monenco Consultants Limited.

Ministry of Northern Development and Mines, **Peat and Peatland Resources of Ontario**, Ontario Geological Survey, Open File Report 5631, 5632, 5633 and Miscellaneous Paper 144.

# Part 2: Technology Assessments

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## 6-1 Introduction

.1 This chapter discusses technologies for the production of electricity from municipal solid waste (MSW).

.2 The ultimate objective of an MSW treatment system is to dispose of the waste materials in an acceptable manner and, if possible, to recover useable energy.

.3 Municipal solid waste can be used as a source of fuel for electrical energy production, district heating, industrial processes, or cogeneration.

.4 The technologies and equipment required to generate electricity from MSW fuels are proven and well understood. Emission control technology is being developed to meet increasingly stringent regulations.

.5 Figure 6-1-1 illustrates the three principal methods by which energy is recovered from MSW.

.6 "Landfill gas" technologies burn the gases produced by the anaerobic decomposition of MSW.

.7 "Mass burn" technologies use direct firing of untreated and largely unseparated MSW to fuel steam-electric power plants.

.8 "Refuse derived fuel" (RDF) results from the processing of MSW into uniform and easily handled combustible material. Typically RDF is a by-product of processes which recover reusable and recyclable materials from municipal waste.

.9 Most of the municipal solid waste fuel is considered to be a renewable resource because the combustible fraction is composed mainly of renewable biomass.

.10 In 1991 the Ontario government stated that it will not approve new municipal solid waste facilities.

## 6-2 Fuel/Energy Source

.1 Municipal solid waste is comprised of residential and commercial refuse composed of combustible and non-combustible materials. MSW is a mixed mass with varying physical and chemical properties.

*Figure 6-1-1: Methods of Recovering Energy from Municipal Solid Waste*

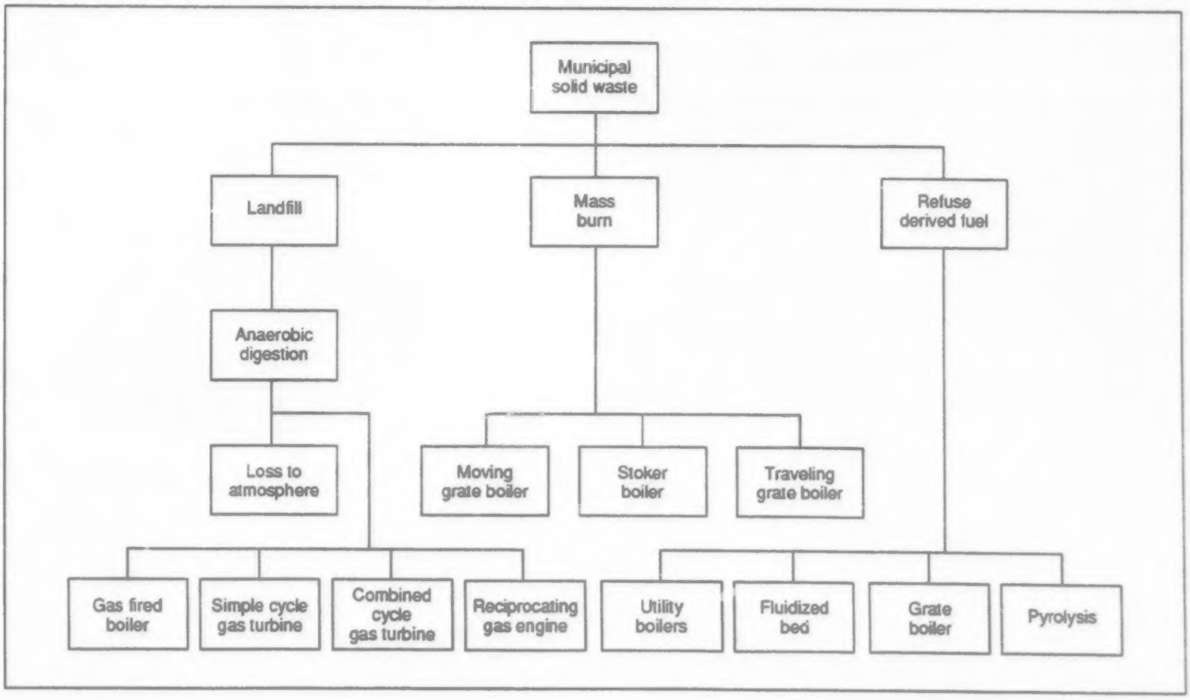
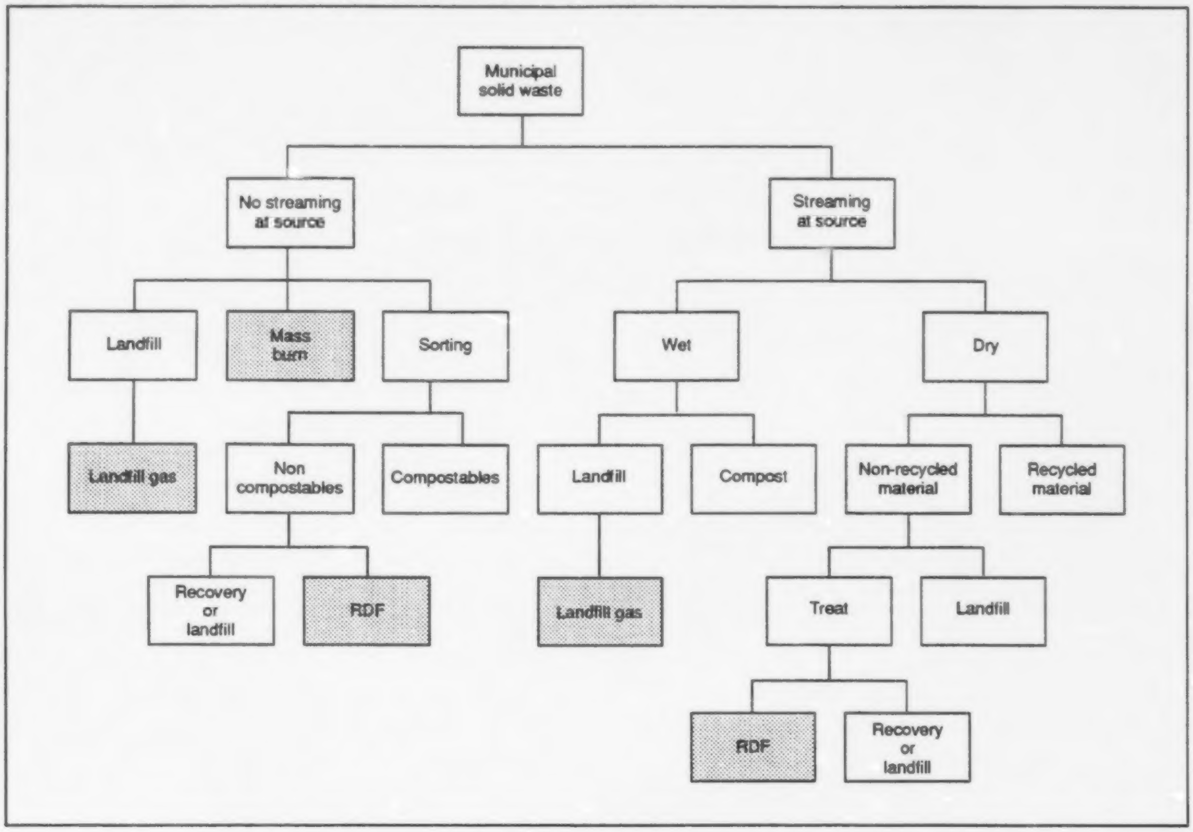

Municipal solid waste
Landfill
Mass burn
Refuse derived fuel
Anaerobic digestion
Loss to atmosphere
Moving grate boiler
Stoker boiler
Traveling grate boiler
Gas fired boiler
Simple cycle gas turbine
Combined cycle gas turbine
Reciprocating gas engine
Utility boilers
Fluidized bed
Grate boiler
Pyrolysis

*Figure 6-2-1: Methods of Collecting and Dispersing of Municipal Solid Waste*


Municipal solid waste
No streaming at source
Streaming at source
Landfill
Mass burn
Sorting
Wet
Dry
Landfill gas
Non compostables
Compostables
Landfill
Compost
Non-recycled material
Recycled material
Recovery or landfill
RDF
Landfill gas
Treat
Landfill
RDF
Recovery or landfill

.2 MSW contains dust particles, on the one hand, and bulky items such as furniture, tires and appliances, on the other.

.3 Moisture content varies considerably and is highly dependent on local climatic conditions.

.4 As Figure 6-2-1 illustrates there are many methods of collecting and disposing of municipal solid wastes.

.5 The figure identifies five routes by which fuels can be derived for energy production using landfill gas, mass burn and refuse derived fuel (RDF) technologies.

.6 The composition and energy content of municipal solid waste varies greatly; but the energy content is generally significantly lower than that of fossil fuels.

.7 The quality of the municipal solid waste as a fuel for the generation of electricity, depends on several factors including the percentage of combustibles and moisture content.

.8 The quantity of MSW available for electricity generation depends on several factors, including:

- the size of nearby urban centres,
- the degree of implementation of reduction, reuse, and recycling programs, and,
- the time of year.

.9 Figure 6-2-2 shows that combustibles made up about 80 to 85 percent of municipal solid waste in the U.S. and Canada in the late 1970s; however, these ratios may change over time depending on the success of waste reduction programs.

*Figure 6-2-2: Composition of MSW from Selected Locations (percent by weight)*

| Component | U.S. National Average 1979 | Ontario Average 1977 | Hamilton Average 1982 | Canada National Average |
|---|---|---|---|---|
| **Combustibles** | | | | |
| Paper | 33.5 | 38.8 | 35.0 | 36.5 |
| Food waste | 17.0 | 30.55 | 14.0 | 27.6 |
| Yard waste | 17.5 | 3.30 | 13.0 | 6.1 |
| Plastics | 3.6 | 4.86* | 5.9* | 5.2* |
| Rubber, leather | 2.6 | – | – | – |
| Textiles | 2.0 | 3.55 | 2.7 | 4.3 |
| Wood | 3.2 | 3.36 | 5.2 | 4.2 |
| Miscellaneous organics | – | 0.31 | – | 1.1 |
| **Total** | **79.4** | **84.81** | **75.8** | **85.0** |
| * May include rubber and/or leather. | | | | |
| **Non-Combustibles** | | | | |
| Glass, ceramics | 9.9 | 8.27 | 8.2 | 8.4 |
| Metals: | | | | |
| • Ferrous | (8.0) | (5.34) | 7.7 | – |
| • Aluminum | (0.9) | (0.77) | – | – |
| • Other | (0.3) | (0.04) | 0.07 | – |
| Sub-total | 9.2 | 6.15 | N/A | 6.6 |
| Fines | – | 0.77 | 5.7 | – |
| Miscellaneous | 1.5 | – | 1.9 | – |
| **Total** | **20.6** | **15.19** | **24.2** | **15.0** |

*Figure 6-2-3: Composition of Canadian Refuse (percent by weight) According to Season of the Year*

| Component | Spring | Summer | Fall | Winter |
|---|---|---|---|---|
| **Combustibles** | | | | |
| Paper, cardboard | 33.9 | 38.9 | 36.6 | 36.5 |
| Food waste | 28.4 | 24.6 | 24.9 | 32.9 |
| Vegetation, yard waste | 12.3 | 4.4 | 6.1 | 0.8 |
| Plastic, rubber | 4.7 | 5.4 | 5.7 | 5.1 |
| Textiles | 3.7 | 4.3 | 4.4 | 4.7 |
| Wood | 2.7 | 5.0 | 5.7 | 3.5 |
| Miscellaneous organics | 0.9 | 0.9 | 1.7 | 1.2 |
| **Total** | **86.6** | **83.5** | **85.1** | **84.7** |
| **Non-Combustibles** | | | | |
| Glass, ceramics | 7.6 | 9.7 | 8.1 | 8.1 |
| Metals | 5.8 | 6.8 | 6.8 | 7.2 |
| **Total** | **13.4** | **16.5** | **14.9** | **15.3** |

.10 Figure 6-2-3 shows that, with the exception of seasonal yard waste, the composition of MSW is relatively constant throughout the year.

### 6-2-1 Landfill Gas

.1 Landfill gas is produced during anaerobic decomposition of garbage buried under thick layers of earth.

.2 The gas is 40 to 60 percent methane by volume, the remainder being largely carbon dioxide.

.3 The higher heating value, also called gross heating value, of typical landfill gas is approximately 17,000 kilojoules per cubic metre (kJ/m$^3$) while natural gas, which is almost pure methane, has a value of 37,000 kJ/m$^3$, over double that of landfill gas.

.4 The amount of recoverable landfill gas depends on the type of waste deposited and the ratio between the surface area and depth of the landfill.

.5 Landfills vary in volume. Greater Toronto's largest landfill at Keele Valley has a design capacity of 20 million tonnes.

.6 The 18 million tonne Brock West landfill has received waste from approximately 1 million people for 15 years and currently produces enough landfill gas to generate 21 MW of electric power.

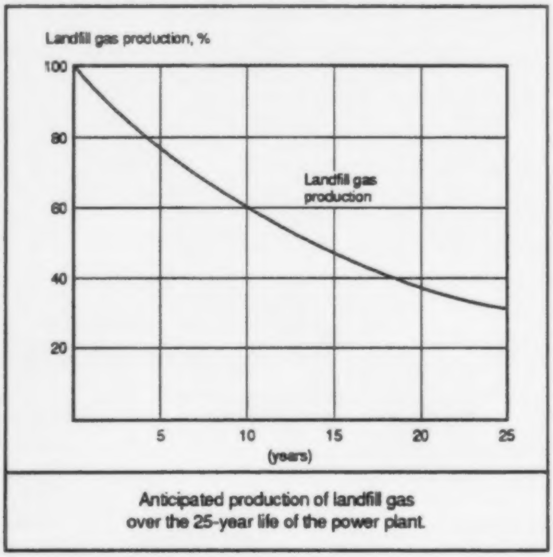
.7 About 70 cubic metres of raw landfill gas is produced from each tonne of solid waste at the Mountain View landfill site in California. (James, 1980)

.8 The rate of gas extraction has to be adjusted to an optimum level at which gas yield is highest and the ingress of air is low enough not to affect either the heating value or the rate of anaerobic digestion.

.9 Landfills can be inoculated with bacteria as layers of MSW are deposited to hasten gas production and shorten landfill settling time.

.10 As shown in Figure 6-2-4, landfill gas is produced over many years but yield declines with time, limiting the economic life for energy recovery to approximately 30 years. (Wallace, 1991)

***Figure 6-2-4: Variation of Landfill Gas Yield with Time [after I.P. Wallace, 1991]***



Anticipated production of landfill gas over the 25-year life of the power plant.

After I.P. Wallace, 1991, *Power Engineering*, Jan 1991.

### 6-2-2 Mass Burn

.1 The fuel for mass burn plants is untreated but sometimes pre-sorted municipal solid waste. The composition of typical MSW was shown in Figure 6-2-2.

.2 A typical mass burn plant requires 45 tonnes of refuse to produce 1 megawatt of power for 24 hours (24 MWh).

.3 Today, the Greater Toronto Area produces enough MSW to support electricity generation ranging from approximately 120 to 145 MW, depending on the degree of recycling.

.4 For a producer of electricity from MSW, the cost of fuel could be negative since municipalities generally would pay a "tipping fee" to the mass burn plant to accept their garbage.

.5 The higher heating value for an average composition of MSW containing some moisture is around 9,000 to 11,000 kilojoules per kilogram (kJ/kg).

### 6-2-3 Refuse Derived Fuel

.1 As previously discussed, refuse derived fuel (RDF) results from the processing of MSW into uniform and easily handled combustible material.

.2 Typically RDF is a by-product of processes which recover reusable and recyclable materials from municipal waste.

.3 Refuse derived fuel may be comprised of materials such as shredded paper and plastics, fluff from junked automobiles, and rubber tire "crumbs".

.4 These materials can be burned as is, or they can be densified into briquettes for ease of handling, transportation and combustion.

.5 The refuse treatment plants may be on site or removed from the point of electricity generation.

.6 RDF has a higher heat content than unsorted and untreated municipal solid waste, typically in the range of 12,000 to 13,000 kJ/kg.

.7 RDF can be used alone or co-fired with another fuel such as coal. Co-firing is rare in utility boilers but more common in industrial processes requiring heat.

.8 Plasma pyrolysis is a process under development by which RDF materials may be broken down to release combustible gases that can be condensed into oil or burned to produce electricity.

.9 The high temperature of the process is expected to fuse the remaining solids into a glass-like material which immobilizes toxic substances.

.10 At present, the energy output from plasma pyrolysis of RDF does not sufficiently exceed the energy input to make this process attractive for electricity generation.

.11 Other pyrolysis processes (for example, thermal pyrolysis) are being investigated in small pilot plants to produce oils and other valuable chemicals.

.12 The advantage of the thermal pyrolysis process is that gas quantities for cleanup are minimized and the oils may be burned in utility boilers if they are technically and environmentally acceptable.

## 6-3 Technology Description

.1 This section describes landfill gas, mass burn and RDF technologies and assesses their potential to provide electrical energy for use in Ontario.

### 6-3-1 Landfill Gas

.1 New landfill sites can be designed originally with a network of pipes to facilitate recovery of the landfill gas, or recovery wells and pipes can later be retrofitted at existing sites.

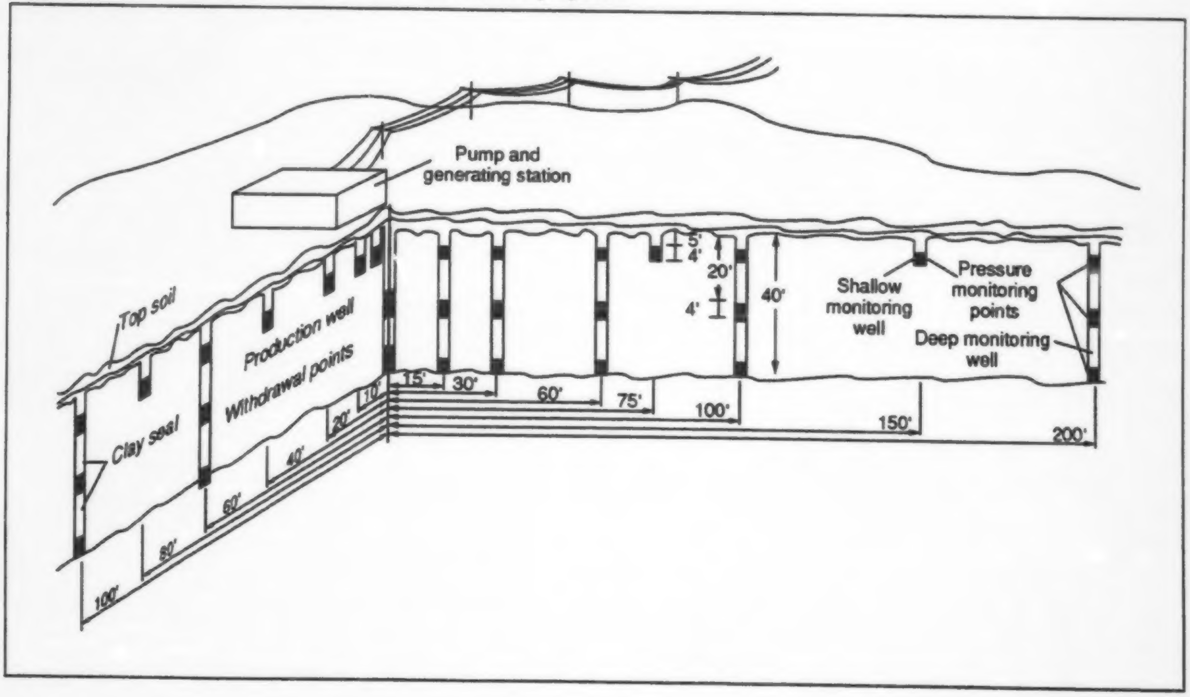
.2 Figure 6-3-1 shows a sectional view of a landfill gas recovery system.

.3 Individual gas wells draw gas from about a 40 meter radius. Pumping is required to prevent the gas from seeping out of the landfill area and to force the extracted gas through burner nozzles.

.4 In general the larger the landfill site the more cost effective is the installation of facilities for the generation of electricity from landfill gas.

.5 As previously shown in Figure 6-1-1 landfill gas can be burned in gas turbines, gas-fired boilers, or reciprocating gas (automotive) engines.

*Figure 6-3-1: Sectional View of a Landfill Gas Recovery System*


Pump and generating station
Top soil
Production well
Withdrawal points
Clay seal
5'
4'
20'
4'
40'
Shallow monitoring well
Pressure monitoring points
Deep monitoring well
15'
30'
60'
75'
100'
150'
200'
10'
20'
40'
60'
80'
100'

.6 Valves have to be incorporated in the collection system to control landfill gas flow from the various points. These valves require periodic adjustment.

.7 The choice of technology is influenced by the amount and quality of the gas available.

.8 Typically, reciprocating engines are used at small landfill sites, gas turbines are used at medium-sized landfill sites, and gas-fired boilers are constructed at large landfill sites.

.9 Boilers are most tolerant of impurities contained in landfill gas; gas turbines less tolerant, and reciprocating engines least tolerant of impurities.

.10 Most jurisdictions require that stationary engineers be on hand to operate high pressure steam boilers, whereas gas turbines and reciprocating engines can be operated remotely.

### 6-3-2 Mass Burn

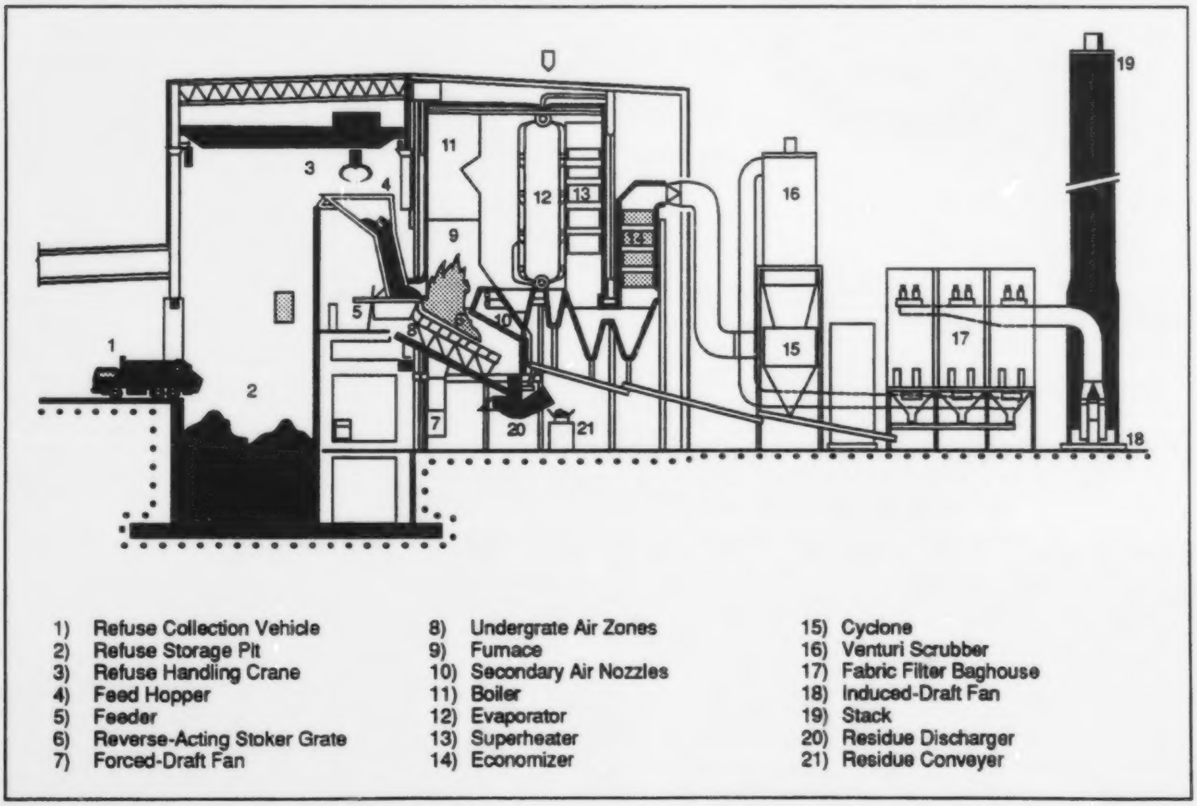
.1 Mass burning is considered to be a simple and proven method of converting MSW to thermal energy using more or less standard incineration and generating equipment.

.2 The main feature of mass burning systems is incineration of waste "as received" with no pre-treatment and minimal sorting.

.3 Figure 6-3-2 illustrates the burning of wastes on a grate and the handling of residual gases and solids.

.4 Some mass burn systems open garbage bags in a drum or similar device and the loosened refuse is mechanically sorted into ferrous metal, non ferrous metal, glass and grit and combustible streams. The combustible stream is composed mainly of paper and plastic. It is a better fuel than raw MSW and yields lower heavy metal emissions.

*Figure 6-3-2: MSW Mass Burn System – Grate Technology*


19
11
3
4
12
13
16
9
5
8
10
15
17
1
2
7
20
21
18
1) Refuse Collection Vehicle
2) Refuse Storage Pit
3) Refuse Handling Crane
4) Feed Hopper
5) Feeder
6) Reverse-Acting Stoker Grate
7) Forced-Draft Fan
8) Undergrate Air Zones
9) Furnace
10) Secondary Air Nozzles
11) Boiler
12) Evaporator
13) Superheater
14) Economizer
15) Cyclone
16) Venturi Scrubber
17) Fabric Filter Baghouse
18) Induced-Draft Fan
19) Stack
20) Residue Discharger
21) Residue Conveyer

.5 Mass burning systems are modular, often prefabricated, and range in unit size from 50 to 1000 tonnes per day of refuse throughput.

.6 There are several types of MSW combustors, the most common of which are waterwall, modular and refractory systems.

.7 Typically the systems employ grates on which the refuse is agitated and burned.

.8 Figure 6-3-3 illustrates "waterwall" technology which is quite similar to that used at coal burning stations. Figure 6-3-4 illustrates "modular" technology in which one or more "factory built" units are employed to produce steam for a common turbine.

.9 Figure 6-3-4 also illustrates the "refractory" technology furnace containing a lined fire chamber.

.10 Air passes through the refuse layer on the grate and additional air may be introduced above the fire to achieve complete combustion and regulate the temperature for $NO_x$ suppression.

.11 At some installations, steam is extracted to supply heat to nearby industries, hospitals or similar users of low grade heat.

.12 Up to 10 percent of the generator's gross electricity output may be required to operate the plant itself.

.13 Pollution control equipment may include either wet-dry or dry scrubbers with fabric filter baghouses to collect particulates.

*Figure 6-3-3: MSW Mass Burn System – Waterfall Technology*

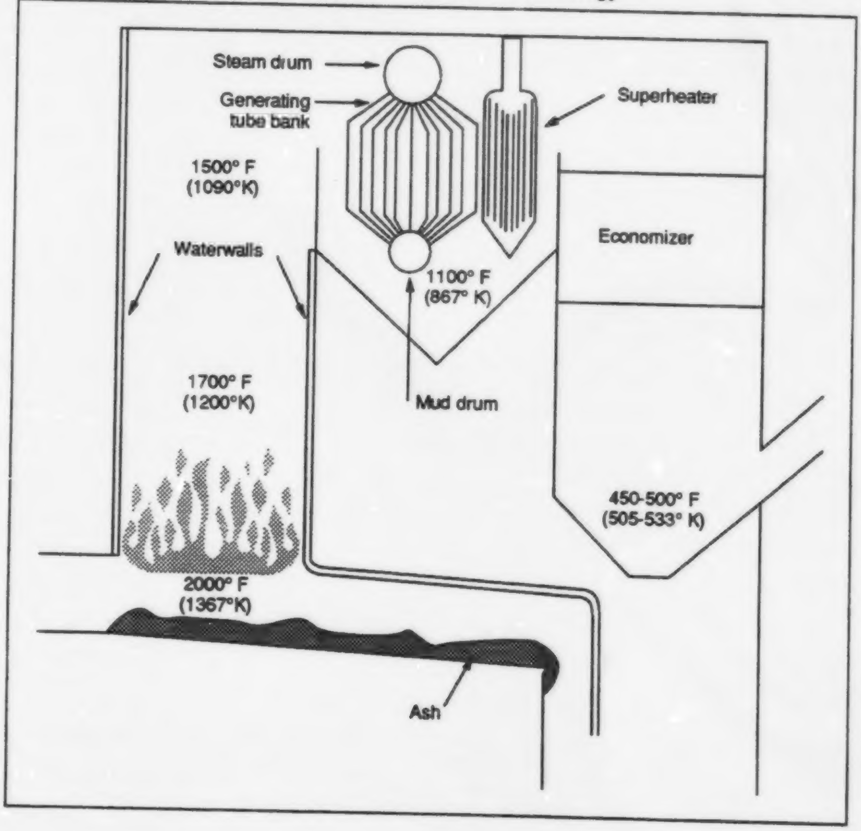
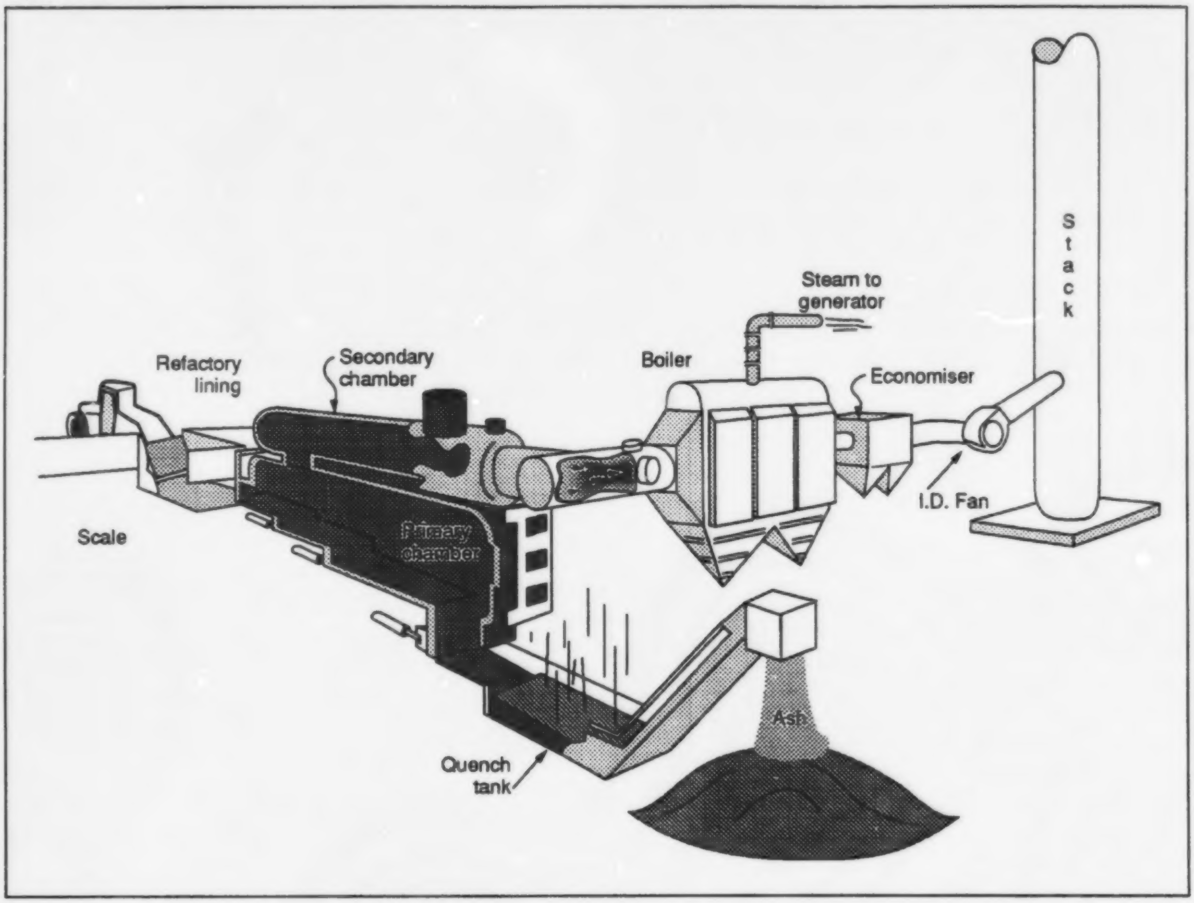

Steam drum
Generating tube bank
Superheater
1500° F (1090°K)
Economizer
Waterwalls
1100° F (867° K)
1700° F (1200°K)
Mud drum
450-500° F (505-533° K)
2000° F (1367°K)
Ash

*Figure 6-3-4: MSW Mass Burn System – Modular Refractory Technology [Consumat]*



.14 It is difficult to maintain flue gas emissions within limits during start-up and shut-down, a factor necessitating several hours of operation with a clean fuel such as wood waste, landfill gas, natural gas or oil when the mode of operation is changed.

.15 Operating the plant continuously minimizes corrosion of the flue gas treatment system by entrained chemicals.

### 6-3-3 RDF – Solid Waste Processing

.1 MSW can be sorted to remove recyclable materials such as metals, glass and some plastics. The residue has little or no commercial value and although some can be composted it is usually incinerated or disposed of as landfill. Alternatively, this residue can be used as RDF.

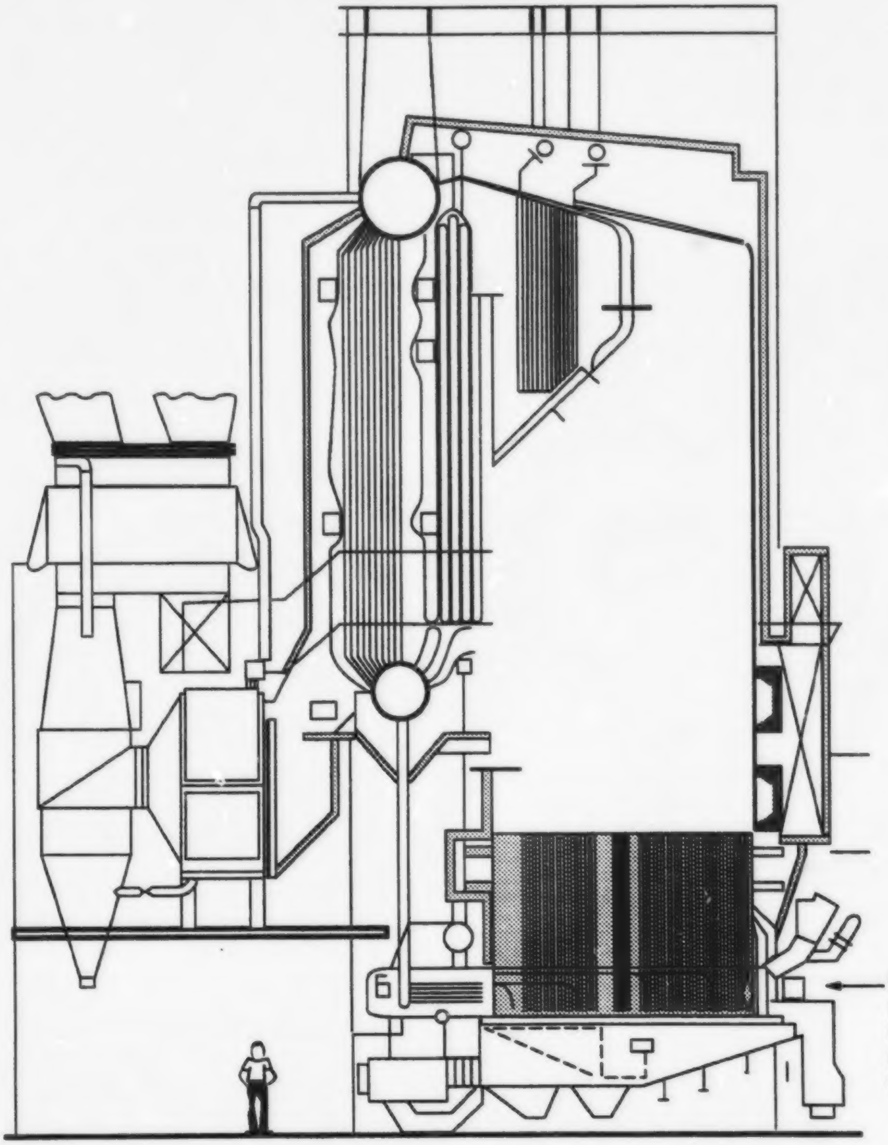
.2 Combustible waste is shredded into pieces approximately 5 cm across or converted to uniformly-sized pellets for combustion on-site or at a remote energy production facility.

.3 RDF can be burned in combustors of various sizes and designs including small stokers, fluidised bed, or travelling grate boilers. An RDF separating and combustion facility is higher in cost than a mass burn plant and yields less electrical energy due to higher station service power requirements.

.4 Some utility boilers can be modified to co-fire RDF with the fossil fuel for which they were originally designed.

.5 Figure 6-3-5 illustrates an RDF co-firing system in which RDF is burned with fossil fuel to produce electricity.

*Figure 6-3-5: RDF Co-Firing System [Babcock]*



Boiler modifications including grate and fuel handling for RDF

.6 Today, electric utilities are often requested by waste processing entrepreneurs to mix processed waste with the regular fuel. However when RDF is co-fired additional fuel handling equipment and pollution controls may be required.

.7 Common operational problems experienced by utilities co-firing RDF include:

- slag formation on upper furnace walls,
- boiler tube corrosion,
- altered flue gas composition,
- fly and bottom ash contamination,
- fuel handling problems, and
- additional instrumentation, control and monitoring requirements.

.8 Those problems can reduce unit reliability and precipitator efficiency.

.9 Old utility boilers usually do not have flue gas treatment systems to handle the new emissions. A fluidized bed combustor exhausting into an existing utility boiler may control those emissions effectively.

## 6-4 Experience

### 6-4-1 World Experience: Landfill Gas

.1 Generators burning landfill gas range in size from less than 1 MW to about 25 MW.

.2 According to one report (Lawson, 1989) systems have been installed in 20 countries worldwide, producing the energy equivalent of over two million tonnes of coal per annum.

.3 One U.S. manufacturer claims that 65 of its reciprocating engines are running on landfill gas.

.4 In 1989 West Germany claimed 23 utility-owned landfill gas generating systems and another 32 operated by non-utility organizations.

.5 The Germans utilize even small landfill sites, and in one instance produce 420 kW using a reciprocating engine and generator housed in a prefabricated building the size of a two-car garage; however, limited engine life has resulted from corrosive components in the gas.

.6 A landfill site in California utilizes two 3 MW gas turbine generators. The power requirement to operate the plant is approximately 500 kW.

### 6-4-2 World Experience: Mass Burn

.1 Incineration of waste has been used as one method to reduce the volume of waste in densely populated countries where landfill sites have been difficult to find.

.2 The recovery of thermal and electrical energy from the incineration process has become a standard approach to make large operations economic.

.3 Many municipalities in Europe and Japan incinerate municipal solid waste at central locations where the high pressure steam is used to generate electricity and the low pressure steam is distributed for district heating of apartment buildings, commercial buildings, hospitals, special industries, swimming pools, greenhouses, and other industrial or commercial users.

.4 Mass burning is the most common method of energy recovery from waste. Figure 6-4-1 identifies world-wide, the growing list of MSW energy recovery facilities in 1989. (OH, D&D 89171, 1989). Figure 6-4-2 is a photograph of the 40 MW mass burn facility at Millbury, Massachusetts, U.S.A.

.5 There are various grate systems available for mass burn combustors. Five European manufacturers account for 85 percent of the types of grates installed.

### 6-4-3 World Experience: RDF – Solid Waste Processing

.1 As early as 1886 an electric utility in Hamburg, Germany co-fired refuse during a cholera epidemic. In those days utility boilers were of the grate type making the addition of solid waste relatively simple.

.2 Nine electric utilities in the U.S. have at some time modified boilers and co-fired refuse derived fuel with coal, oil or wood waste. (Smith, 1988). As of 1990 four utility companies were reported to be still continuing with the practice. The companies that stopped co-firing did so because the low cost of RDF was outweighed by the increased costs associated with the resultant operational problems.

Figure 6-4-2: Mass-Burn Facility at Millbury, Maine

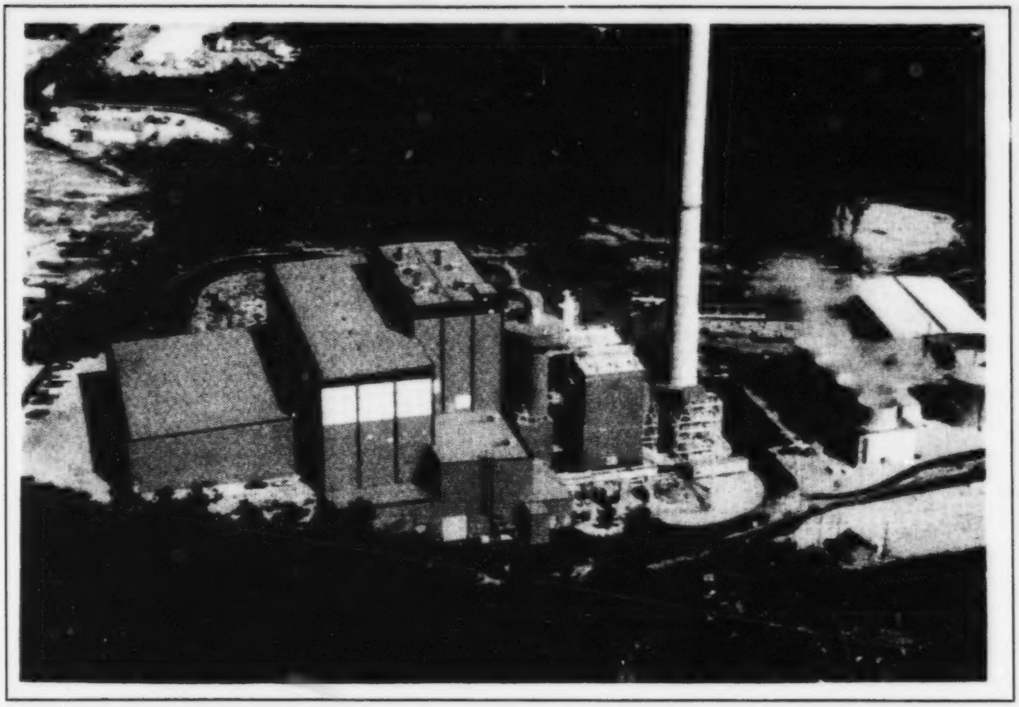


Figure 6-4-3: Brock Road Landfill Gas Facility at Pickering, Ontario

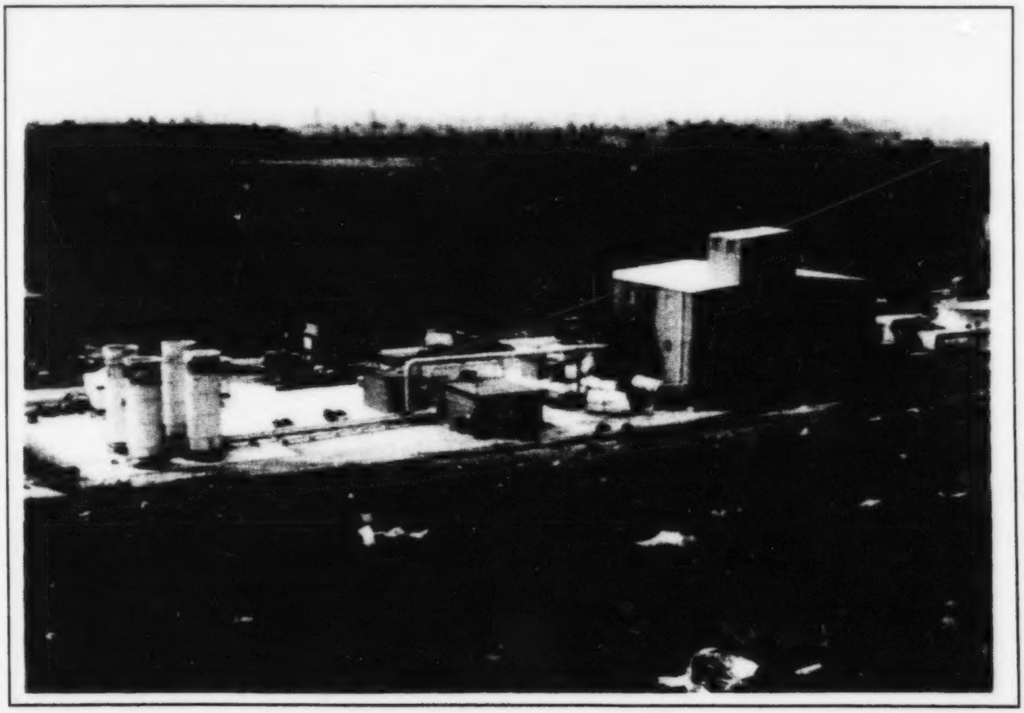


*Figure 6-4-4: Canadian MSW Mass Burn Facilities with Energy Recovery*

| Facility/Locality | Province | MW | Tonnes/day |
|---|---|---|---|
| Burnaby | British Columbia | 7 | 612 |
| Victoria Hospital | Ontario | 6.25 | 249 |
| Peel Resources* | Ontario | 9 | 400 |
| Laidlaw-SWARU (RDF) | Ontario | 3 (Gross) | 500 |
| Charlottetown | Prince Edward Island | 0.2 | 73 |
| Quebec City | Quebec | steam | 535 |
| Montreal | Quebec | N/A | 662 |

* Scheduled to be placed in service in 1992.

*Figure 6-4-5: Comparison of Emissions from London Victoria Hospital Mass Burn Facility with Ministry of Environment Standards*

| Emission Parameter | Victoria Hospital | MOE Point of Impingement Standard | Units |
|---|---|---|---|
| Particulates | 0.97 | 100 | micrograms/m$^3$ ($\mu$g/m$^3$) |
| Sulphur Dioxide | - | 830 | $\mu$g/m$^3$ |
| Carbon Monoxide | - | 6,000 | $\mu$g/m$^3$ |
| Hydrogen Chloride | - | 100 | $\mu$g/m$^3$ |
| Cadmium | 0.001 | 5 | $\mu$g/m$^3$ |
| Chromium | - | 5 | $\mu$g/m$^3$ |
| Lead | 0.008 | 10 | $\mu$g/m$^3$ |
| Mercury | 0.02 | 5 | $\mu$g/m$^3$ |
| Nickel | - | 5 | $\mu$g/m$^3$ |
| Zinc | - | 100 | $\mu$g/m$^3$ |
| Dioxin & Furans | 0.98 | 450 | picograms/m$^3$ (pg/m$^3$) |
| Pentachlorophenol | - | 60 | nanograms/m$^3$ (ng/m$^3$) |
| PCBs | - | 450 | ng/m$^3$ |

.4 This 500 tonnes per day processing and incineration plant in Hamilton operates 24 hours a day, five days a week producing 3 MW of electric power. Presently the plant also consumes approximately 3 MW and therefore does not sell significant amounts of energy. Redesign of the plant is ongoing and it should produce approximately 1 MW of net power after the currently planned steam utilization improvements are implemented.

.5 Although there are many concerns about emissions from MSW facilities, tests conducted in 1988 show that at the SWARU facility air borne emissions are well within the 1989 Ministry of Environment standards for point-of-impingement as shown in Figure 6-4-7. (MOE, 1991)

## 6-5 Potential System Application

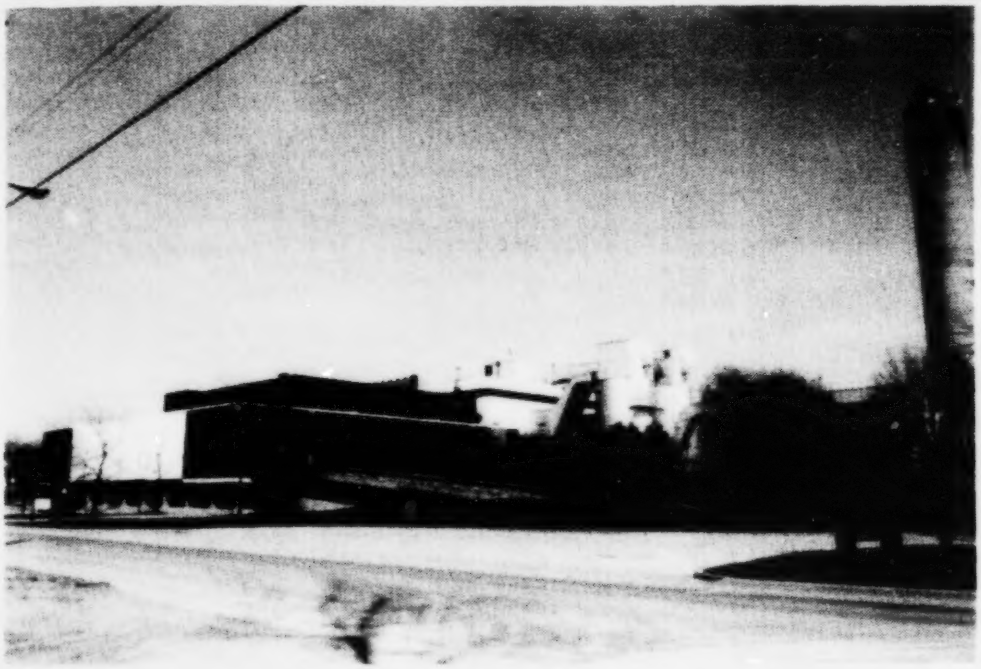
### 6-5-1 Potential System Application: Landfill Gas

.1 Landfill gas generators would need to be operated 24 hours a day for economic and technical reasons. The gas would have to be flared off or accumulated when the unit is not operating. For this reason, these units are best suited for base-loaded operation.

.2 In Canada landfilling of MSW has been and still is the norm in many municipalities. This presents many opportunities for landfill gas electrical generation systems.

.3 Landfill gas electric generators could be dispersed sources of generation.

*Figure 6-4-6: SWARU Facility at Hamilton, Ontario*



### 6-5-2 Potential System Application: Mass Burn

.1 MSW mass burning plants would need to be operated around the clock for economic and technical reasons (see Section 6-3-2). For this reason, these units are best suited for base-loaded operation.

.2 MSW burning plants could be sited not far from population centres and may reduce transmission and distribution requirements.

.3 Experience indicates that capacity factors of 80 to 90 percent are achievable.

.4 For example, a 1,400 tonnes per day mass burning plant at Millbury, Massachusetts, generates 45 MW gross power or 40 MW net. The capacity factor based on throughput is 85 to 90 percent.

.5 This performance is representative of other modern mass burning plants and performance may be guaranteed by the manufacturer.

### 6-5-3 Potential System Application: RDF

.1 For economic and technical reasons, it would be desirable to operate RDF burning plants as much as possible. Frequent shut-downs and start-ups are not desirable. For this reason, these plants are suited to base load applications.

.2 For example, the SEMASS plant near Cape Cod is normally operated 24 hours a day, seven days a week.

.3 Experience in the 1980s (SWARU- Hamilton) indicates that the capacity factor of RDF facilities may be lower than equivalent mass burning plants because of the added complexity of the fuel processing system. However, these problems are likely to be corrected in future designs.

.4 Dedicated RDF burning plants could be sited not far from population centres and may reduce transmission and distribution requirements.

.5 A dedicated RDF burning generating station may add capacity to the dispersed generation mix promoted by many utilities.

.6 The conversion of existing fossil-fired boilers to enable RDF co-firing does not add additional generating capacity to the system; however, it may reduce the overall efficiency and dependability of that plant.

.7 Capacity is added to the system when an old mothballed generating unit is brought back into operation burning RDF.

.8 RDF may not be available in consistently sufficient quantities at locations where utility boilers exist to warrant the installation of equipment to burn RDF.

### 6-6 Environmental Considerations

.1 This section of the review discusses environmental considerations, both natural and social, associated with municipal solid waste.

### 6-6-1 Natural Environment

.1 This section discusses environmental issues associated with MSW technologies (landfill gas, mass burn and RDF) and their impact on the natural environment, under the headings of air, land and water.

*Air: Landfill Gas*

.2 Methane, if allowed to escape from landfill sites, contributes significantly more to the greenhouse effect (20 to 50 times more per unit weight than $CO_2$) than the gases resulting from its combustion.

.3 At some landfill sites methane is flared to reduce the possibility of explosion and to control objectionable odours.

.4 Generation of electricity using landfill gas would make use of energy otherwise wasted and may displace the need for other generation.

.5 Electricity generation using landfill gas may reduce on-site atmospheric emissions. For example, low $NO_x$ burners and flue gas recirculation equipment installed in boilers can reduce the $NO_x$ resulting from the landfill gas combustion process.

.6 Boilers may produce less $NO_x$ than reciprocating engines or combustion turbines fuelled by landfill gas.

.7 Oxides of sulphur are produced only as traces because landfill gas is low in sulphur content.

.8 Ash resulting from the generation or flaring process is insignificant, being similar to that created by the combustion of natural gas.

*Air: Mass Burn*

.9 Mass burning of MSW can produce atmospheric emissions of:

- acid gases (HCl, $SO_x$, HF, HBr, $NO_x$),
- heavy metals (zinc, cadmium, mercury, lead, nickel, chromium), and
- trace organics such as chlorinated benzenes, phenols, dioxins and furans.

*Figure 6-4-7: Comparison of Emissions from the SWARU Facility with Ministry of Environment Standards*

| Emission Parameter | SWARU | MOE Standard | Units |
|---|---|---|---|
| Particulates | 11.7 | 100 | µg/m$^3$ |
| Sulphur Dioxide | 36.1 | 830 | µg/m$^3$ |
| Carbon Monoxide | 76.9 | 6000 | µg/m$^3$ |
| Hydrogen Chloride | 38.9 | 100 | µg/m$^3$ |
| Cadmium | 0.002 | 5 | µg/m$^3$ |
| Chromium | 0.002 | 5 | µg/m$^3$ |
| Lead | 0.05 | 10 | µg/m$^3$ |
| Mercury | 0.005 | 5 | µg/m$^3$ |
| Nickel | 0.005 | 5 | µg/m$^3$ |
| Zinc | 0.056 | 100 | µg/m$^3$ |
| Dioxin & Furans | 6.53 | 450 | pg/m$^3$ |
| Pentachlorophenol | 0.265 | 60 | ng/m$^3$ |
| PCBs | 0.005 | 450 | ng/m$^3$ |

.10 Sorting of MSW at the curbside, waystation or at the generating plant could remove a significant proportion of materials that are likely to release toxic emissions (e.g., batteries, plastics such as PVC insulated wires, and partly filled paint cans).

.11 Wet or dry scrubbers can be used to control $SO_x$, HCl, HF and HBr emissions.

.12 $NO_x$ emissions can be reduced by a variety of methods including modified combustion processes and selective catalytic reduction.

.13 Dry/wet scrubbing in combination with baghouse filters can be used to reduce emissions of particulates, trace organics and many heavy metals. (Power, 1991). Europeans are using expensive but highly effective flue gas cleaning and recycling systems which produce inert and recyclable end products from the collected impurities. (ABB,1990)

.14 The modular total cleaning and recycling systems, as they are known, have the following main components:

- a filsorption (filter plus absorption) stage separating microscopic particles, heavy metals and trace organics by a combination of filtering, absorption and chemical reaction,
- an absorption stage which collects the acidifying gas components and produces recycleable products such as hydrochloric acid, chloride or sulphate compounds,
- a reduction stage in which nitrogen oxides are transformed into ordinary nitrogen gas, and
- a sanitizing stage in which reactive ash from the filsorption process is melted into glass and metal concentrate.

.15 Odours emanating from MSW are largely contained in the enclosed tipping floor area from which combustion air is drawn. The chemicals which produce the odours are consumed in the combustion process.

### *Air: RDF*

.16 Environmental considerations for refuse derived fuel are similar to those for mass burning of sorted MSW. Emissions would depend on the waste content and the combustion facilities used.

.17 Although RDF is likely to be a cleaner burning fuel than untreated MSW, there is some likelihood that the RDF would include materials that, when burned, produce hazardous emissions. Controls similar to those used when burning MSW may be required for some RDF fuels.

.18 Co-firing RDF with another fuel (e.g., coal) could result in RDF pollutants contaminating the whole flue gas stream. Those flue gases are larger in volume and therefore more difficult and expensive to treat and control than gases which result from burning either coal or RDF separately. Because RDF tends to have low sulphur content, co-firing may reduce the utility's overall $SO_x$ emissions.

### *Land: Landfill Gas*

.19 The addition of facilities to produce energy from landfill gas would not markedly alter the land use impact the landfill site would have had in any case.

.20 Landfill gas recovery or flaring would tend to reduce the risk of that gas seeping into nearby basements.

### *Land: Mass Burn*

.21 Generation of electricity from MSW would reduce the volume of waste requiring disposal. About 10 to 15 percent of the MSW remains as ash (bottom and fly ash) which must be disposed of as landfill.

.22 Like bottom ash, fly ash may also contain both recyclable materials and toxins.

.23 Magnetic separators can be used to remove ferrous metals from the bottom ash for recycling.

.24 It may be necessary to dispose of the remaining ash as a hazardous waste because of the potential for ground water contamination by leachates from metals including arsenic, cadmium, chromium, copper, mercury, lead and zinc. (Bramryd, 1988)

.25 Alternatively ash can be melted into glass and metal concentrates for disposal or reuse.

*Land: RDF*

.26 All of the fly ash and bottom ash from a co-fired utility boiler may be classified as hazardous waste requiring special disposal in a hazardous waste facility whereas coal ash can be used for road bases and building materials.

*Water: Landfill Gas*

.27 Landfill gas powered generating plants can be designed to produce no water effluents.

.28 The energy recovery system would not change the impact the landfill would have had on the ground water since water leachate has to be controlled through appropriate design in any case.

.29 The removal of moisture and contaminants from landfill gas in gas turbine or gas engine powered plants result in a residue that is considered to be a hazardous waste in some jurisdictions. The water borne residue is sent to a hazardous liquid waste facility and the oil-like residue is also removed.

*Water: Mass Burn*

.30 A mass burn plant may be designed so that no cooling or process water leaves the plant (except by evaporation) since water required for bottom ash quenching and other processes may be recycled.

.31 On-site water treatment systems may include settling ponds, pH controls, heavy metal settling, treatment to remove trace organics, and filtration and disinfection before reuse.

*Water: RDF*

.32 A plant fuelled exclusively with RDF would have environmental effects similar to those described for a mass burn plant.

.33 Water requirements for a plant co-fired with RDF would not differ substantially from those of the original plant although additional water treatment facilities might be required.

### 6-6-2 Social Environment

.1 This section discusses issues associated with MSW technologies and their impact on the social environment, under the headings of socio-economic effects and societal considerations.

*Socio-Economic Effects*

.2 Large MSW facilities would likely be located near large urban centres, particularly the Greater Toronto Area (GTA). This may preclude the provision of employment benefits in parts of the Province seeking additional employment opportunities (northern and eastern Ontario).

.3 Limited employment and economic opportunities would likely arise in the Greater Toronto Area.

.4 The handling and transportation of MSW could cause concerns regarding traffic, noise, odour and property values. However, areas where these social concerns may arise will depend on the method of disposal for MSW. MSW facilities can be designed to minimize odour problems. Prudent waste processing and buffer areas would be important. Sensitive groups are likely to be concerned with the potential effects of an MSW facility.

.5 Ash disposal for some MSW options may pose an additional concern for local communities.

.6 Members of the public may be concerned with on-site storage of waste during maintenance and shut-down periods. These concerns can be mitigated through proper management practices.

*Societal Considerations*

.7 As with solid waste disposal facilities, MSW facilities would have low social acceptance as they would not be consistent with the character of local communities. In addition, concerns about air emissions from the combustion of MSW would lessen community acceptance.

.8 Fuel sorting prior to combustion augments the opportunity to reduce the final quantity of waste to be disposed of by society. Significant quantities of valuable material could be recovered.

.9 Although MSW facilities may result in local social concerns, on a regional basis, burning MSW may be considered favourably in the context of reducing landfill requirements.

.10 The landfill cost burden for Ontario citizens may be reduced if mass burn and RDF options were developed.

## 6-7 Operational Considerations

### 6-7-1 Maintenance

.1 Ongoing, online preventative maintenance would be carried out throughout the year in accordance with a preventative maintenance schedule based on supplier specifications and good power plant practice.

.2 *Landfill Gas:* On occasions when the plant had to be shut down for maintenance the landfill gas would be flared off.

.3 *MSW Mass Burn:* The use of several combustors in parallel allows individual furnaces to be taken out of service when repairs to the grate, refractory lining, boiler tubes, flue gas treatment systems and other equipment have to be performed. Operations may continue at reduced output for the duration of the maintenance period and if necessary MSW can be accumulated on the tipping floor.

.4 *RDF:* Maintenance would be similar to that for a mass burn system or the conventional fossil fuel burning system in the case of co-firing.

### 6-7-2 Staffing

.1 *Landfill Gas:* A gas turbine or gas engine system may require five people in total to operate the plant on a single shift basis. At night and on weekends the staff is off duty but one designated person equipped with a beeper is on stand-by. A steam-based generating system would require nine staff operating in shifts.

.2 *MSW:* A 50 MW mass burn plant may require a staff level of 43 operating in shifts.

.3 *RDF:* A 55 MW RDF processing and combustion facility is quite labour intensive and may require 125 people working in shifts.

### 6-7-3 System Life

.1 MSW mass burn facilities costed in this review are assumed to have a life of 30 years.

.2 Landfill gas plants are generally designed to correspond with the projected availability of gas from the landfill.

.3 Some earlier MSW plants have had very short operating lives either because of poor design or because the environmental control equipment became outdated.

### 6-7-4 Heat Rate and Efficiency

.1 The heat rate for a landfill gas system is approximately 12,500 kJ/kWh. For MSW or RDF burning system the heat rate, based on the higher heating value, is 20,000 kJ/kWh.

.2 For MSW mass burn facilities, efficiency is not a significant factor because the lower the efficiency the more waste is burned and the more tipping fees are collected.

## 6-8 Development Issues

### 6-8-1 Landfill Gas

.1 The technology to convert landfill gas to electrical energy is available today and development issues relate to refinements to:

- improve the economics through higher efficiency,
- decrease operating costs of steam cycle plants,
- reduce $NO_x$ emissions of gas turbines and engines, and
- improve gas cleanup for increased plant life.

### 6-8-2 Mass Burn

.1 Emission limits have become more stringent over the years. Manufacturers of MSW combustion equipment have kept up with these requirements by adding pollution control devices or by adopting more appropriate technologies that are more effective. New and better flue gas cleanup technologies may be required as regulations change.

.2 Public acceptance may be an impediment to the implementation of large scale MSW mass burning energy recovery systems. Public acceptance may improve if a clear benefit can be shown by integrating mass burn plants into district heating systems, similar to the European and Japanese practice.

.3 More widespread use of fluidized bed mass burn combustors may allow a high percentage of aluminum and other metals to be recovered from the bottom ash.

### 6-8-3 RDF

.1 Many of the development issues related to RDF combustion are similar to those associated with mass burn technologies described in this section.

.2 Special waste such as rubber tires would require dedicated systems to be installed to dispose of these materials using environmentally acceptable methods.

.3 RDF can be used as fuel in industrial processes to produce cement or building materials. This would minimize the need to landfill the ash and may also produce electrical energy in some of the processes.

## 6-9 Option Selected for Costing

.1 Based on the above assessment, the following energy from waste option is selected as representative of a typical installation in order to prepare representative costs.

### 6-9-1 Option: 50 MW Mass Burn Plant

.1 This mass burn plant would receive municipal solid waste from the Greater Toronto Area from which recyclable materials have been diverted through a program of Reduction, Reuse and Recycling (3Rs) as well as home composting. The facility would consist of three waterwall combustors each having a nominal capacity of 825 tonnes per day, a wet/dry lime scrubber and a baghouse to collect particulates. A single turbine generator would be common to the three combustors and so would be the stack.

.2 Waste heat utilization in the form of district or industrial heating would be desirable to improve the economics and reduce overall environmental impact but it is not included in the costing of this option on the assumtion that the distribution piping system would not be in place at the mass burn plant site.

.3 Why 50 MW? This size plant is of reasonable dimensions and fuel requirements to limit the collection radius and traffic caused by trucks. If more MSW is to be burned, other plants would be built in different locations.

.4 Why mass burn? This is the most popular technology in many countries. It is reliable in operation and it is suitable for waste from which a significant portion of non-combustible material has been diverted. Mass burning can achieve a volume reduction of 85 to 90 percent. Companies have enough experience with mass burn systems to offer complete services including management of the environmental assessment process, plant design, financing and operation.

.5 Why waterwall combustors? This is also one of the most popular technologies in the world that is suitable for combustors in the 825 tonnes per day range.

.6 Why wet/dry lime scrubber and baghouse? This is the best available technology presently used in North America for which cost data are available. The higher cost European gas cleanup system could also be used in conjunction with the mass burn technology but equipment and OM&A cost figures are not available.

.7 Why a single turbine generator? A common, large turbine generator will have a better efficiency and be of lower cost than smaller separate units. A turbine bypass is used to dump steam if this is necessary during a turbine generator outage.

## 6-10 Costs and Performance

.1 This section discusses the performance and cost assumptions for the municipal solid waste (MSW) option assessed. The measure used to assess the MSW option is the cost/benefit ratio previously discussed in Part 1, Section 1-7.

.2 A 50 MW mass burn plant was selected for evaluation, as explained in Section 6-9.

*Figure 6-10-1: Municipal Solid Waste Plant – Performance Assumptions*

| Option – 50 MW Mass Burn Plant | | | |
|---|---|---|---|
| Description | Useful Life (years) | Annual Capacity Factor (%) | Thermal Efficiency (%) |
| 50 MW Mass Burn | 30 | 80 | 19.9 |

### 6-10-1 Performance Assumptions

.1 Figure 6-10-1 summarizes the performance assumptions of the MSW option.

### 6-10-2 Calculation of Benefits – MSW Power Plants

.1 The benefits of MSW power plants to an electricity system are two-fold – the value of the energy produced by the installation and the value of the "capacity" provided by that installation to the system. This latter benefit, known as the "capacity credit", is discussed in Part 1, Section 1-7.

.2 In addition, the MSW option assessed here would be eligible for credits for avoiding transmission and distribution costs and losses, since MSW plants would likely be located close to large population centres and would likely be connected to a municipal utility's distribution system. These credits are discussed below.

#### *Value of Energy Produced*

.3 Since this option is fully dispatchable and is assumed to be operated base-loaded, the annual energy production would be split evenly over the four categories of summer peak energy, winter peak energy, summer off-peak energy and winter off-peak energy.

.4 The present value (PV) of the energy produced by the 50 MW MSW power plant is estimated at $97.0 million based on an annual capacity factor of 80 percent.

#### *Capacity Credit*

.5 MSW power plants are eligible for a full capacity credit as they are dispatchable.

.6 The present value of the capacity credit is estimated to be $38.8 million.

#### *Transmission and Distribution Credits*

.7 Included in the above present values of capacity and energy are credits for avoiding bulk electricity system costs ($12/kW/yr), regional supply system costs ($7/kW/yr), distribution system costs ($10/kW/yr), and a credit for avoiding transmission and distribution losses (7 percent of the total value of energy and capacity).

#### *Summary of Benefits*

.8 Figure 6-10-2 summarizes the present value of the benefits associated with the MSW power plant.

*Figure 6-10-2: Summary of Benefits – MSW Option*

| Option – 50 MW MSW Mass Burn Plant | |
|---|---|
| Energy Benefit (M$ 1991) | 97.0 |
| Capacity Benefit (M$ 1991) | 38.8 |
| Total Benefits (M$ 1991) | 135.8 |

### 6-10-3 Cost Estimates

.1 Ontario Hydro has no experience with the design, construction, installation and operation of MSW power plants.

.2 The cost estimates are developed based mainly on reports commissioned by Ontario Hydro and prepared by experts in the field. Cost estimates are based on the most current information available to Ontario Hydro. The costs are intended to provide an indication of a range of costs and not a definitive estimate of the cost of each option.

.3 The cost estimates presented are 1991 costs.

.4 The costs presented are those for electricity as the only product. However, electricity, if produced, would be a by-product of a process whose principal aim is the reduction of the volume of municipal solid waste. Another by-product, useable heat, is also produced and could be sold, for example for district heating. Section 6-10-5 discusses the potential value of the useable heat for this MSW option, given the assumption about the amount and value of the heat discussed in Part 1, Section 1-7.

.5 Capital & OM&A cost estimates for the municipal solid waste option are shown in Figure 6-10-3 below.

*Figure 6-10-3: Cost Estimates – Municipal Solid Waste Option*

| Cost Component | 50 MW MSW Mass Burn Plant (Current Costs) |
|---|---|
| Initial Capital ($/kW) | 3,491 |
| Later Capital ($/kW/yr) | 103 |
| OM&A ($/kW/yr) | 107 |

.6 Fuelling costs for an MSW incineration facility would be negative. Operators of MSW power plants would be paid a "tipping fee" to accept MSW for burning. Current tipping fees are about $150 per tonne in Metropolitan Toronto. Tipping fees paid by municipalities to the plant operator constitute the main source of revenue. The sale of electricity, if produced, constitutes a secondary source of revenue. The "benefits" associated with the operations of MSW plant are thus the tipping fees and the revenues from the sale of electricity. The benefits which accrue from the receipt of tipping fees are evaluated and included in the cost/benefit ratios shown below in Section 6-10-4.

### *Present Value of Costs*

.7 The present value of the capital and OM&A costs of the MSW option are summarized in Figure 6-10-4.

*Figure 6-10-4: Present Value of Costs – MSW Option*

| Cost Component | 50 MW MSW Mass Burn Plant (Current Costs) |
|---|---|
| Total Capital (M$ 1991) | 145.3 |
| OM&A (M$ 1991) | 50.5 |
| Total (M$ 1991) | 195.8 |

## 6-10-4 Cost/Benefit Ratios

.1 Figure 6-10-5 shows calculated cost/benefit ratios for the MSW option at different assumptions regarding the tipping fees which an operator would be paid. As discussed above, tipping fees are a benefit to the operator since they are a source of revenue. The level of tipping fees is the main factor which influences the economics of MSW mass burning plants.

.2 The results in Figure 6-10-5 indicate that, using Ontario Hydro's incremental system values of power and energy and Ontario Hydro's financial factors, the cost/benefit ratio for the MSW option assessed here would be less than one for tipping fees above approximately $17 per tonne. At this level of tipping fees, the capital and operating costs of the plant would be recovered through the sale of electricity and through tipping fees over the assumed 30-year life of the plant. The level of tipping fees at which the cost/benefit ratio would be equal to 1.0 for a private owner/operator would likely be different, since that owner/operator would likely assess the costs and benefits in a different manner taking into account such items as taxes and incentives.

## 6-10-5 Sensitivity Analysis

.1 Sensitivity analyses are not meaningful for the MSW option. The overwhelming factor in assessing the economics of MSW options is the assumed tipping fee. The sensitivity of the cost/benefit ratios to the tipping fee is shown above in Figure 6-10-5. Further sensitivities, based on changes in capital and OM&A costs, or upon changes in performance factors would not be helpful in assessing the economics of MSW options.

*Figure 6-10-5: Summary of Costs and Benefits – MSW Options*

| Option – 50 MW MSW Mass Burn Plant | | | | |
|---|---|---|---|---|
| | Tipping Fees (per tonne) | | | |
| Factor | $150 | $60 | $30 | $17.39 |
| PV of Capital & OM&A Costs (M$ 1991) | 195.8 | 195.8 | 195.8 | 195.8 |
| PV of Benefits (ex. tipping fees) (M$ 1991) | 135.8 | 135.8 | 135.8 | 135.8 |
| PV of Tipping Fees (M$ 1991) | 518.0 | 259.0 | 127.8 | 60.0 |
| Net Present Value (M$ 1991) | 458.0 | 199.0 | 67.8 | 0.0 |
| Cost/Benefit Ratio | 0.3 | 0.5 | 0.7 | 1.0 |

### 6-10-6 Potential Value of Useable Heat

.1 The economic evaluations shown above consider electricity as the only product. MSW-fuelled power plants would likely be installed in cogeneration applications producing both electricity and useable heat, for example, for district heating. In most cases, electricity, if produced, is a by-product of MSW incineration.

.2 The heat is valued on the basis of Ontario Hydro's forecast of the industrial direct price of natural gas. In addition, as discussed in Part 1, Section 1-7, it is assumed that 80 percent of the energy content of the fuel is recovered in a cogeneration application as electricity and useable heat.

.3 In this analysis, it is also assumed that no additional costs would be incurred for the installation and operation of heat recovery and distribution equipment.

.4 The potential value of the useable heat produced, expressed as a levelized unit energy benefit (LUEB), is estimated to be 5.6 ¢/kWh for this 50 MW MSW mass burn plant.

.5 Note that, because of the low fuel-to-electricity conversion efficiency (19.9 percent) of this MSW plant and the assumption that 80 percent of the energy content of the fuel is recovered as either useable heat or electricity, the amount of and hence calculated value of the useable heat (5.6 ¢/kWh) is relatively high.

### 6-10-7 Cost Summary

.1 The results in Figure 6-10-5 show that, from a purely economic perspective, the burning of MSW would be an economical method of generating electricity for Ontario, given current tipping fees at about $150 per tonne in the Greater Toronto Area. The point at which the generation of electricity from an MSW plant of this size would become economical is at a tipping fee of about $17 per tonne. However, the Ontario government has stated that it will not permit new MSW mass burn facilities.

.2 The use of municipal solid waste power plants in combined heat and power applications would make these more economical because of the combined revenues from the sale of both electricity and heat.

## 6-11 Potential

### 6-11-1 Scenario Descriptions

.1 The potential for MSW power plants is assessed under the three scenarios described earlier in Part 1, Section 1-8. These scenario descriptions are repeated below:

*Scenario 1:* In this scenario, it is assumed that there is no improvement in current costs and technological status by the year 2000. The potential contribution by the year 2005 is assessed.

*Scenario 2:* In this scenario, an attempt is made to account for cost and technological improvements which may occur by the year 2000. Given these improvements, the potential contribution by the year 2005 is reassessed.

*Scenario 3:* The projections in this highly speculative scenario are based on assumptions that significant improvements in technology and costs could occur by the year 2010. The potential contribution by the year 2014 is assessed.

### 6-11-2 Background to Potential Contribution Estimates

.1 Ontario Hydro's 1990 Non-Utility Generation Plan documents projections of the potential contribution of municipal solid waste options in the period up to the year 2015.

.2 As previously discussed, current government policy prohibits the establishment of new MSW incineration facilities. This is the main factor presently affecting the potential contribution of MSW.

.3 The technologies available to convert MSW to electrical energy are fully developed and could be implemented if government policies change.

.4 Should government policies change, MSW incineration facilities would likely develop in the Greater Toronto Area because of the high tipping fees.

.5 Landfill gas facilities are currently permitted. Should government policies regarding new MSW incineration facilities not change, landfill gas production will increase.

.6 Should government policies change to permit new MSW incineration facilities, landfill gas production will gradually decline.

.7 The projection of potential shown below under the three different scenarios are attempts to reflect uncertainties regarding future government policy.

### 6-11-3 Projections of Potential

.1 Figure 6-11-1 shows the projection of the potential contribution of MSW option under the following three scenarios.

.2 In Scenario 1 it is assumed that no further MSW facilities will be installed by the year 2005 because of current government policies. Electricity production from landfill gas options are assumed to increase from the current 22 MW to approximately 60 to 70 MW by the year 2005.

.3 In Scenario 2 since government policies are assumed to be the same no new MSW incineration facilities would be installed; therefore, improvements in costs and technology are immaterial. Landfill gas options are expected to be as in Scenario 1.

.4 In Scenario 3 government policies are assumed to have changed, resulting in approximately 100 to 200 MW of new MSW incineration facilities being installed by the year 2014. Landfill gas production would be expected to decline because existing landfill sites would become depleted and few new gas-producing landfill sites would be expected.

*Figure 6-11-1: Forecast of Potential Contribution for Municipal Solid Waste (MSW)*

| Scenario | Assumptions | Major Factors Affecting Potential | Cost Compared to Conventional Generation | Potential | | Potential Applications |
|---|---|---|---|---|---|---|
| | | | | MW | By Year | |
| 1 | • Current technology.<br>• Current cost. | • Limited resource. | | | | |
| | **Mass Burn:**<br>• Tipping fees sufficiently high to offset high capital cost.<br>• Government policy prohibits additional facilities. | • Government policy. | Lower | <15 | 2005 | Non-utility generation. |
| | **Landfill Gas:**<br>• Resource is depleted whether used or not.<br>• As per Scenario 1. | • Limited number of sites. | Lower | 60 – 70 | 2005 | Non-utility generation. |
| 2 | • Government policy as above. | | | | | |
| | **Mass Burn:**<br>• Minor improvement in technology and costs. | • As above. | Lower | <15 | 2005 | Non-utility generation. |
| | **Landfill Gas:**<br>• Technology matures.<br>• Permits granted for landfill sites. | • Limited number of sites. | Lower | 60 – 70 | 2005 | Non-utility generation. |
| 3 | • Further improvement in technology.<br>• Further improvement in cost. | | | | | |
| | **Mass Burn:**<br>• Permitted under stringent regulation. | • Government policy permits incineration after 3Rs. | Lower | 100 – 200 | 2014 | Non-utility generation. |
| | **Landfill Gas:**<br>• Majority of sites have been in service from mid-1990s. | • Depleted resource. | Lower | 25 | 2014 | Non-utility generation. |

## 6-12 Overall Assessment

.1 Municipal solid waste (MSW) has been developed as a fuel for electricity generation because of the opportunity to reduce the volumes of waste by means of incineration and to make use of a low or negative cost fuel.

.2 The technology for generating electricity from MSW is well established and used in many parts of the world. Development of equipment and processes to meet progressively stricter environmental requirements is ongoing.

.3 Forms of MSW fuel include unsorted and partially sorted waste (mass-burn technology), the gas generated by the anaerobic decomposition of waste in landfill sites (landfill gas), and fuels derived from the processing of waste (refuse derived fuel – RDF).

.4 Although RDF has a higher heating value than unsorted MSW, an RDF separating and combustion facility costs more than a mass burn plant of equivalent capacity and yields less electrical energy due to higher station service power requirements. RDF can be co-fired with a fossil fuel. However, uncertainties regarding waste content require that stringent emission controls be added to a converted fossil-fuel burning facility.

.5 From a purely cost perspective the burning of MSW would be an economical method of generating electricity in Ontario given the tipping fees in force in the Greater Toronto Area. The availability of fuel at negative or low cost makes electricity production a revenue producing by-product of the MSW facility. As indicated in Section 6-10, electricity production could be economical at much lower tipping fees than currently exist in Metropolitan Toronto. The use of MSW plants in combined heat and power applications would make them more economical.

.6 Municipal solid waste fuel is a limited resource which can be consumed at more or less the rate at which it is produced.

.7 Energy-from-waste facilities tend to be close to larger population centres where the electrical energy will find use. The generating plant is usually tied into the electrical grid. There is little potential for energy-from-waste in off-grid applications.

.8 Energy-from-waste facilities would produce base load energy in most cases because landfill gas recovery is constant and large refuse burning facilities are operated around the clock to minimize corrosion of flue gas cleaning systems.

.9 As discussed in Section 6-11, potential generation of electric power from existing landfill gas sites in Ontario is estimated to be 30 MW. This potential is expected to increase to 60 to 70 MW by the year 2005. These resources are being utilized by private developers who make use of an energy resource that would otherwise be flared for safety and odour suppression reasons.

.10 For some MSW technologies, emissions controls and the disposal of ash as a hazardous material would be required.

.11 Local community impacts such as increased traffic, noise, dust, odour and concerns about property values may arise from the implementation of large scale MSW facilities. On a regional basis, social acceptance of MSW may be higher, given the potential for reducing the volume of waste going directly into landfills.

.12 The major barrier to implementation of MSW mass burn facilities is public acceptance of the potential environmental impacts of MSW incineration systems. The Ontario Provincial Government announced in 1991 that it would not approve new MSW incineration facilities.

.13 Assuming that 50 percent of garbage is recycled, currently it would be possible to generate up to 145 MW of electric power by mass burning refuse from the Greater Toronto Area. As discussed in Section 6-11, the potential contribution of MSW incineration plants to the electricity supply mix in Ontario, assuming provincial government approval and some increase in the total amount of garbage production could be as high as 200 MW by the year 2014.

.14 Advantages of MSW as a fuel for electricity generation include:

- the renewable and indigenous nature of the fuel,
- reduction of waste volume, and
- use of an otherwise wasted resource.

.15 Barriers to wide-scale introduction of MSW-fuelled energy recovery systems in Ontario include:

- limited resource,
- lack of public acceptance,
- government policy, and
- low tipping fees outside the Greater Toronto Area.

## 6-13 References

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# Part 3: Summary and Conclusions

## Chapter 1: Summary

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## Chapter 2: Conclusions

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### 1-1 Introduction

.1 This section summarizes the information contained in Part 2 of this review.

.2 Section 2 of Part 3 – Conclusions, summarizes Ontario Hydro's assessments of the six alternative energy technologies.

.3 Part 1 of the report provides background information which is not summarized here.

### 1-2 Status of Technologies

.1 Figure 1-1 summarizes information about the current and predicted technological development of the six technologies selected for review. The figure also shows current and potential applications of these technologies during the planning period.

.2 Photovoltaic technology is developing rapidly and technological breakthroughs may occur which will significantly reduce the cost of manufacturing photovoltaic cells. The first on-grid applications of photovoltaic technology would likely involve dispersed non-utility generation, with electricity being used primarily at the point of generation.

.3 Wind power technologies have made steady progress in the areas of increased reliability, reduced cost, and the ability to operate at low wind speeds. This steady progress is expected to continue. Wind power will likely be applied in niche applications involving off-grid hybrid systems (e.g., wind/diesel) where the cost of the displaced generation is high. Ontario's first on-grid applications will likely be in the form of dispersed non-utility generation (i.e., single wind turbines or wind farms).

.4 Fuel cell technology is developing rapidly. Some fuel cell technologies are well developed for niche applications such as space programs in which size, weight and efficiency are more important than cost. Of the three major fuel cell types assessed in the review only one (phosphoric acid) can be considered to be commercially available. A second (molten carbonate) may be commercially available by the year 2000 and the third (solid oxide) sometime after the year 2000. Development will continue because of the advantages of fuel cells over conventional fossil fuel technologies (higher efficiencies, modularity, lower noise and lower emissions). The useable heat makes fuel cells attractive in cogeneration applications.

.5 Implementation of fuel cells will be constrained by capital cost, fuel cost and demonstration of reliable operation. A major challenge is to demonstrate reliable operation of fuel cell power plants for tens of thousands of hours. Fuel cell power plants will likely first become cost-effective in combined heat and power applications where the value of the useable heat produced could partially offset electricity production costs.

.6 Currently, biomass-fuelled power plants rely on well established combustion technologies which perform at around 20 to 25 percent thermal efficiency. Research is being conducted toward the development of biomass-fuelled integrated gasification combined cycle (IGCC) systems. If successful such systems would increase the fuel utilization efficiency and reduce the capital costs of biomass-fuelled electrical generation. Ongoing research in several countries, including Canada, aims at developing biomass species suitable for energy plantations. Success in this area could lead to reduced costs for biomass fuels for electrical generation. Biomass power plants can be economical for electricity generation when fuelled with waste biomass if the fuel is available free of charge or at negative cost.

.7 Peat is of interest as a fuel for electricity generation in Ontario mainly because it is a significant indigenous resource. The technology for burning milled peat is proven. Peat has been used extensively as a fuel for electricity generation in Ireland and Finland, often co-fired with other fuels such as wood and coal, but has not been applied in North America. Cost is a major factor limiting the replacement of fossil fuels by peat. Peat is more costly than oil, gas and coal because of its lower energy density and high moisture content. Peat-fuelled plants are physically larger, and of higher capital cost than fossil-fuelled plants per unit of capacity. If Ontario's peat resources are to be developed wet mining techniques may prove more cost-effective given Ontario's small, separated bogs and climatic conditions. Those techniques will require specialized equipment and involve considerable research and development effort. Development of this resource will likely have to address environmental issues including disruption of the peat bog ecology.

***Figure 1-1: Current and Predicted Technological Development and Uses***

| Technology | Current | Predicted by Year 2000 | Predicted by Year 2014 |
|---|---|---|---|
| Photovoltaics | • Silicon technology established.<br>• Niche applications and demonstration projects.<br>• Hybrid systems at remote sites.<br>• Uneconomic compared to conventional generation in Ontario for grid electricity. | • Technological breakthroughs and manufacturing economies of scale could lower costs.<br>• Remote site (off-grid) applications.<br>• Load displacement applications (on-grid) may begin to appear if costs low enough.<br>• Likely still uneconomic compared to conventional generation. | • Further technological breakthroughs possible. Incorporation in building materials could lead to increased use. |
| Wind | • Advanced variable wind speed turbines under development to lower energy costs.<br>• Market penetration limited because of intermittent availability of power.<br>• Uneconomic compared to conventional generation in Ontario for grid electricity. | • Advanced variable wind speed turbines could be increasingly cost competitive.<br>• Market penetration limited because of intermittent availability of power.<br>• Likely still marginally less economic than conventional generation. | • Further technological advances could lead to increased viability at sites of moderate wind speed.<br>• Economies of scale could lower costs. |
| Fuel Cells | • PAFC close to being commercial.<br>• Uneconomic compared to conventional generation in Ontario for grid electricity.<br>• PAFC demonstration projects being constructed.<br>• Small-scale demonstration projects for MCFC and SOFC. | • PAFC likely established. MCFC likely commercial. SOFC in advanced demonstration phase.<br>• Small fuel cells fuelled by natural gas likely for dispersed cogeneration and/or utility applications.<br>• Utility scale technologies in development and demonstration stage.<br>• Likely still uneconomic compared to conventional generation. | • MCFC likely established. SOFC likely commercial.<br>• Small fuel cells fuelled by natural gas likely for dispersed cogeneration and/or utility applications.<br>• Fuel cells or IGCC could emerge as the preferred option for coal-fuelled generation.<br>• Economics uncertain. |
| Biomass | • Conventional combustion technology proven.<br>• Waste biomass plants economic and in use in cogeneration applications in Ontario.<br>• Limited by fuel availability.<br>• Plantation options in assessment stage and not economic. | • High efficiency generation technologies may be available.<br>• Plantation techniques may be proven.<br>• Generation subject to cost-effective fuel availability. | • High efficiency generation technologies may be available.<br>• Generation subject to cost-effective fuel availability.<br>• May become a viable generation option driven by concerns about $CO_2$ emissions. |
| Peat | • Technology proven. Used extensively in Ireland and Finland because of high costs of imported fuels.<br>• Uneconomic in Ontario compared to conventional generation options. | • Implementation on a significant scale in Ontario unlikely because of high costs.<br>• Possible demonstration of advanced peat-fuelled production and peat IGCC technologies. | • High efficiency generation technologies may be available.<br>• Generation subject to cost-effective fuel availability. |
| Municipal Solid Waste | • Technology proven. Small mass burn and RDF plants operating in Hamilton and London.<br>• Landfill gas plant being commissioned.<br>• Government policies prohibit further mass burn plants. | • Landfill gas operations continue.<br>• Mass burn not significantly used because of environmental concerns and government policies.<br>• Capacity limited by available fuel resource. | • Likely unchanged. Depends on success of waste reduction, reuse, recycling initiatives.<br>• Capacity limited by available fuel resource. |

.8 The incineration of municipal solid waste is common in various parts of the world. Electricity, if produced, is a byproduct of the incineration process. The generation of electricity from MSW fuels using conventional combustion technologies is proven and well understood. Emission control technology is available or being developed to meet increasingly stringent regulations. Energy-from-waste facilities tend to be close to larger population centres where the waste is produced and where there is a demand for electricity and heat. The generating plant is usually tied into the electrical grid. There is little potential for energy-from-waste in off-grid applications.

## 1-3 Options Selected for Costing

.1 Figure 1-2 lists the specific options of the six technologies which were selected for economic evaluation in this review. The figure also shows whether each option was evaluated using current (1991) costs only, current and projected (year 2000) costs only, or projected costs only. It also summarizes performance assumptions used in evaluating each of the selected options and shows the fuel or energy source for each option. Note that two fuel cell types, molten carbonate and solid oxide, are not evaluated using current costs. These technologies are yet to be demonstrated on a commercial scale.

*Figure 1-2: Technology Options Selected for Economic Evaluation and Key Performance Assumptions*

| Option | Evaluated Using | | Useful Life Assumed (yrs) | Annual Capacity Factor Assumed (%) | Thermal Efficiency (%) | Fuel/Energy Source |
|---|---|---|---|---|---|---|
| | Current Costs | Projected Year 2000 Costs | | | | |
| **Photovoltaics** | | | | | | |
| 2 kW rooftop residential | YES | YES | 30 | 12 | N/A | Sunlight |
| 100 kW rooftop commercial/industrial | YES | YES | 30 | 12 | N/A | Sunlight |
| **Wind** | | | | | | |
| 10 kW Single Turbine | YES | YES | 25 | 22 | N/A | Wind |
| 20 x 350 kW Wind Farm | YES | YES | 25 | 22 | N/A | Wind |
| **Fuel Cells** | | | | | | |
| 200 kW Phosphoric Acid | YES | YES | 20 | 80 | 36.4 | Natural Gas |
| 200 kW Molten Carbonate | NO | YES | 20 | 80 | 49.1 | Natural Gas |
| 200 kW Solid Oxide | NO | YES | 20 | 80 | 41.7 | Natural Gas |
| 10 MW Phosphoric Acid | YES | YES | 30 | 80 | 41.4 | Natural Gas |
| 10 MW Molten Carbonate | NO | YES | 30 | 80 | 54.5 | Natural Gas |
| 10 MW Solid Oxide | NO | YES | 30 | 80 | 51.9 | Natural Gas |
| **Biomass** | | | | | | |
| 15 MW Conventional Thermal | YES | NO | 30 | 80 | 22.7 | Plantation Wood |
| 75 MW Conventional Thermal | YES | NO | 30 | 80 | 24.9 | Plantation Wood |
| **Peat** | | | | | | |
| 15 MW Conventional Thermal | YES | NO | 30 | 80 | 26.0 | Milled Peat |
| 75 MW Conventional Thermal | YES | NO | 30 | 80 | 26.5 | Milled Peat |
| **Municipal Solid Waste** | | | | | | |
| 50 MW Conventional Thermal | YES | NO | 30 | 80 | 19.9 | Municipal Refuse |

### 1-4 Summary of Cost Evaluations

.1 Figures 1-3, 1-4 and 1-5 summarize the results of the cost evaluations of the options selected for costing under each of the six technologies.

.2 Cost/benefit ratios are provided for the solar, wind and municipal solid waste options for reasons discussed in Part 1, Section 1-7. A cost/benefit ratios of less than one signals an economic option. Levelized unit energy costs are provided for the remaining three technologies (fuel cells, biomass and peat).

.3 With the exception of the municipal solid waste option, three estimates are provided. The point estimates reflect Ontario Hydro's assessment of the cost/benefit ratios or levelized unit energy costs. The lower estimates result from a combination of assumptions which reflect high performance (high benefits) and low costs. The upper estimates result from a combination of assumptions which reflect low performance (low benefits) and high costs.

.4 Figure 1-3 shows that the solar and wind options assessed are uneconomic for the production of electricity supplied to the bulk electricity system in Ontario as indicated by cost/benefit ratios of greater than one. However, the lower estimates indicate cost/benefit ratios approaching one for the wind options.

.5 Figure 1-4 shows that levelized unit energy costs for the fuel cell, biomass and peat options are estimated to be higher than those of conventional generation options. Note that there is a marked improvement shown in the levelized unit energy cost estimates for fuel cells when projected year 2000 costs are used.

.6 Figure 1-5 shows cost/benefit ratios at various tipping fees for the municipal solid waste (MSW) option assessed. The cost/benefit ratio is less than one for tipping fees of greater than about $17 per tonne. This indicates that incineration of MSW could be an economical method of producing electricity in Ontario given that current tipping fees in the Metropolitan Toronto area are in the order of $150 per tonne.

*Figure 1-3: Cost/Benefit Ratios – Solar and Wind Options*

| | Using Current Costs | | | Using Projected Year 2000 Costs | | |
|---|---|---|---|---|---|---|
| | Cost/Benefit Ratio | | | Cost/Benefit Ratio | | |
| Option | Lower Estimate | Point Estimate | Upper Estimate | Lower Estimate | Point Estimate | Upper Estimate |
| **Photovoltaics** | | | | | | |
| 2 kW Rooftop Residential | 4.5 | 7.7 | 18.6 | 1.6 | 2.4 | 6.3 |
| 100 kW Rooftop Commercial/Industrial | 4.0 | 6.7 | 15.7 | 1.4 | 2.1 | 5.4 |
| **Wind** | | | | | | |
| 10 kW Single Wind Turbine | 1.1 | 1.7 | 4.0 | 1.1 | 1.5 | 3.7 |
| 20 x 350 kW Wind Farm | 1.1 | 1.6 | 3.3 | 1.1 | 1.5 | 3.2 |

*Figure 1-4: Levelized Unit Energy Cost Estimates – Fuel Cell, Biomass and Peat Options*

| Option | LUEC (¢/kWh) at 80% ACF | | | LUEC (¢/kWh) at 80% ACF | | |
|---|---|---|---|---|---|---|
| | Using Current Costs | | | Using Projected Year 2000 Costs | | |
| | Lower Estimate | Point Estimate | Upper Estimate | Lower Estimate | Point Estimate | Upper Estimate |
| **Fuel Cells** | | | | | | |
| 200 kW Phosphoric Acid | 10.8 | 14.1 | 19.4 | 8.4 | 10.2 | 14.1 |
| 200 kW Molten Carbonate | N/A | N/A | N/A | 7.0 | 8.5 | 12.6 |
| 200 kW Solid Oxide | N/A | N/A | N/A | 8.0 | 9.8 | 14.6 |
| 10 MW Phosphoric Acid | 8.9 | 11.6 | 15.1 | 6.4 | 7.5 | 9.6 |
| 10 MW Molten Carbonate | N/A | N/A | N/A | 5.7 | 6.9 | 9.8 |
| 10 MW Solid Oxide | N/A | N/A | N/A | 6.1 | 7.4 | 10.5 |
| **Biomass** | | | | | | |
| 15 MW Conventional Thermal | 9.6 | 13.7 | 21.4 | N/A | N/A | N/A |
| 75 MW Conventional Thermal | 6.3 | 9.5 | 14.7 | N/A | N/A | N/A |
| **Peat** | | | | | | |
| 15 MW Conventional Thermal | 14.5 | 19.5 | 29.0 | N/A | N/A | N/A |
| 75 MW Conventional Thermal | 9.4 | 12.2 | 17.2 | N/A | N/A | N/A |
| Typical LUEC for Conventional (Base-loaded) Generation Options* at 80% ACF | 3 to 5 | | | N/A | | |

* For example nuclear and conventional steam cycle coal.
N/A = Not Applicable.

*Figure 1-5: Cost/Benefit Ratios at Various Tipping Fees – Municipal Solid Waste*

| Option - 50 MW Municipal Solid Waste Plant | | | | |
|---|---|---|---|---|
| Tipping Fees (per tonne) | $150 | $60 | $30 | $17.39 |
| Cost/BenefitRatio (Using Current Costs) | 0.3 | 0.5 | 0.7 | 1.0 |

## 1-5 Environmental Considerations

.1 Figure 1-6 identifies environmental considerations associated with the six technologies.

.2 Environmental effects associated with fuel extraction and processing, construction, operations and maintenance and decommissioning were considered. In the case of technologies which would require the purchase of prefabricated items, the management of environmental effects associated with fabrication are assumed to be included in the price of the items and are not addressed in detail.

## 1-6 Assessment of Potential

.1 Figure 1-7 summarizes the potential contribution (in megawatts) to electricity supply for Ontario of the six alternative energy technologies assessed in this review. The figure shows the potential contribution under three different scenarios. These estimates have been adopted by Ontario Hydro for planning purposes.

.2 Figure 1-8 compares the potential contribution under Scenarios 1 and 2 of this assessment with the results of a previous assessment prepared by Ontario Hydro in 1986 (Demand/Supply Options Study) and, for biomass and municipal solid waste, those of a more recent assessment contained in Ontario Hydro's 1990 Non-Utility-Generation Plan.

***Figure 1-6: Summary of Environmental Considerations for Alternative Energy Technologies***

| Option | Environmental Consideration | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Air Emissions | Land Use | Aquatic Effluents | Aesthetics | Solid Waste | Non-Renewable Energy Source | Local Socio-economic Impacts | Other |
| Photovoltaics: Centralized | | ▲ | | ▲ | ▲[4] | | ▲ | PV Manufacture |
| Photovoltaics: Decentralized | | | | | ▲[4] | | | PV Manufacture |
| Wind: Centralized | | ▲ | | ▲ | ▲[4] | | ▲ | |
| Wind: Decentralized | | | | | ▲[4] | | | |
| Fuel Cells | ▲[1] | | ▲[3] | | ▲ | ▲[2] | | Emissions lower than for fossil stations[1] |
| Biomass: Plantation | ▲ | ▲ | ▲ | | ▲ | | ▲ | Plantation sustainability unknown |
| Biomass: Wood Waste | ▲ | | ▲ | | ▲ | | | |
| Peat | ▲ | ▲ | ▲ | | ▲ | ▲ | ▲ | Peatland disruption |
| MSW: Landfill Gas | ▲ | | ▲[5] | | | ▲ | | |
| MSW: Mass Burn/RDF | ▲ | | ▲ | | ▲ | | ▲ | Public/ government acceptability |

**Notes:** 1 – Emissions are fuel dependent. Hydrogen fuel results in electricity, water and heat.
2 – Renewability is fuel dependent.
3 – Fuel cell combined cycle applications would require cooling water.
4 – Primarily during decommissioning. Recycling/reuse opportunities would exist.
5 – If steam electric system is used.

*Figure 1-7: Potential Contribution of Alternative Energy Technologies Under Various Scenarios*

| **Technology** | **Potential by Year 2005 (MW)** | | **Potential by Year 2014 (MW)** |
|---|---|---|---|
| | **Scenario 1** | **Scenario 2** | **Scenario 3** |
| Photovoltaics | < 1 | < 1 | 50 – 100 |
| Wind | < 1 | < 1 | 10 – 40 |
| Fuel Cells | < 1 | < 10 | 300 – 800 |
| Biomass | | | |
| (1) Waste | 100 | 100 | 100 |
| (2) Plantation/Forest | Nil | 20 | 50 – 100 |
| Peat | Insignificant | 20 | 50 – 100 |
| Municipal Solid Waste | | | |
| (1) Landfill gas | 60 – 70 | 60 – 70 | 25* |
| (2) Mass Burn | < 15 | < 15 | 100 – 200 |
| **Totals (Approximate)** | < 190 | < 240 | 685 – 1465 |

* Assumes declining production of landfill gas from sources developed in earlier scenarios.

**Scenario Descriptions**

*Scenario 1:* In this scenario, it is assumed that there is no improvement in current costs and technological status by the year 2000. The potential contribution by the year 2005 is assessed.

*Scenario 2:* In this scenario, an attempt is made to account for cost and technological improvements which may occur by the year 2000. Given these improvements, the potential contribution by the year 2005 is reassessed.

*Scenario 3:* The projections in this highly speculative scenario are based on assumptions that significant improvements in technology and costs could occur by the year 2010. The potential contribution by the year 2014 is assessed.

.3 The amounts identified in Figures 1-7 and 1-8 are in addition to Ontario's existing solar, wind, biomass and MSW capacity.

.4 Note that scenarios are used as guides but cannot be applied uniformly to all six technologies. For example, projections of generation from municipal solid waste depend greatly upon government policy. In the absence of the government's existing policy limiting waste incineration, the favourable costs associated with electricity-from-waste could drive use of the technology to its fuel-limited potential.

*Figure 1-8: Comparison of Potential Contribution Estimates – Alternative Energy Review versus Earlier Estimates*

| Technology | Potential Contribution (MW) | | | |
|---|---|---|---|---|
| | Alternative Energy Review | | Demand/Supply Options Study (1985) (By Year 2004) | 1990 Non-Utility Generation Plan (By Year 2000) |
| | Scenario 1 (By Year 2005) | Scenario 2 (By Year 2005) | | |
| Photovoltaics | < 1 | < 1 | Insignificant | Insignificant |
| Wind | < 1 | < 1 | Insignificant | Insignificant |
| Fuel Cells | < 1 | < 10 | Insignificant | Insignificant |
| Biomass | | | | |
| (1) Waste | 100 | 100 | 50 | 300* |
| (2) Plantation/Forest | Nil | 20 | Nil | Nil |
| Peat | Insignificant | 20 | Insignificant | Insignificant |
| Municipal Solid Waste | | | | |
| (1) Landfill gas | 60 – 70 | 60 – 70 | N/A | |
| (2) Mass Burn | < 15 | < 15 | 50 | 116(1) |
| **Totals** (Approximate) | < 190 | < 240 | 100 | 416 |

* Includes currently installed non-utility generation capacity.

(1) Includes some landfill gas electricity generation.

.1 Based on the information contained in this review, Ontario Hydro's conclusions regarding the potential role in the electricity supply mix for Ontario of the six technologies assessed are summarized below.

## 2-1 Solar

.1 Interest in photovoltaics for electricity generation results mainly from the use of a renewable energy source (sunlight) and negligible emissions to the environment during operation.

.2 Of the available methods of generating electricity from solar energy, the most promising for Ontario is the use of photovoltaics. Photovoltaic technology has been proven as a source of small-scale decentralized electricity generation.

.3 Cost estimates in this review indicate that photovoltaic technology is not currently economic for the production of electricity for the bulk electricity system in Ontario. Current costs are high; however, significant cost reductions are forecast by the year 2000.

.4 The current high cost of photovoltaics compared to conventional generation sources makes it an uneconomic alternative except in remote locations which do not have access to a central electrical grid.

.5 The first on-grid applications of photovoltaics would likely involve dispersed non-utility generation, with electricity being used primarily at the point of generation. Applications which provide a good match between the availability of solar power and the need for power will likely predominate. For example, solar photovoltaics could be used to offset some of the energy required for air conditioning.

.6 Sunlight is a diffuse energy resource requiring collection over large areas. However, photovoltaics can be installed unobtrusively on buildings thereby minimizing land requirements.

.7 Ontario Hydro sponsored surveys indicate that solar power is the second most favoured energy option behind hydro-electric development. Solar energy options are renewable and the social acceptance of solar power is high. Factors given for its support include solar power being perceived as the cheapest source of electricity, a renewable resource and the cleanest form of energy. (Goldfarb, 1986)

.8 Without specific policies to stimulate the development of a provincial-based solar photovoltaic manufacturing industry, regional employment and economic development is expected to be limited to activities associated with the assembling, installation and maintenance of photovoltaic systems.

.9 As discussed in Part 2, Chapter 1, Section 1-11, the potential contribution of photovoltaic technology to the electricity supply mix for Ontario could be as little as 1 MW by the year 2005 to as high as 100 MW by the year 2014 depending on cost and technological developments.

.10 The advantages of photovoltaic technology include:

- use of a renewable energy source,
- high social acceptance,
- no fuel costs,
- low maintenance costs,
- modularity, and
- minimal environmental impact, assuming roof-mounted installation.

.11 Barriers to large-scale implementation of photovoltaic technology include:

- high initial capital costs,
- intermittent availability of power, and
- limited manufacturing capacity at present.

## 2-2 Wind

.1 Interest in wind turbines results from their negligible pollutant emissions and their use of a renewable energy source.

.2 Wind power is a proven technology. Wind power has advanced greatly over the past decade with most development occurring in California and Denmark. Most recent windfarms demonstrate over 95 percent availability for individual machines.

.3 Costs estimates in this review indicate that wind power is not currently economic for the production of electricity for the bulk electricity system in Ontario.

.4 In Ontario, wind power would likely be first applied in niche applications involving off-grid hybrid systems (e.g., wind/diesel), where the cost of the displaced generation is high. Ontario Hydro currently operates a hybrid wind/diesel demonstration project at a remote community.

.5 On-grid application of wind power would likely be in the form of dispersed non-utility generation (i.e., single wind turbines or wind farms).

.6 Energy output from a wind turbine is very site dependent; therefore, in-depth investigation of potential wind sites is required for optimum siting.

.7 Wind farms require large tracts of land; however, much of that land is available for other uses such as agriculture.

.8 The potential for wind power in Ontario is limited by the availability of sites having suitable wind-speeds and its high cost. As discussed in Part 2, Chapter 2, Section 2-11, the potential contribution of wind power to the electricity supply mix for Ontario could be as little as 1 MW by the year 2000 to as high as 40 MW by the year 2014 depending on costs and technological developments.

.9 The advantages of wind energy include:

- use of a renewable energy source,
- no fuel costs,
- no pollutant emissions,
- minimal waste products,
- modularity, and
- social acceptance has generally been high in other jurisdictions.

.10 Barriers to large-scale wind development include:

- limited number of good wind sites in Ontario,
- intermittent availability of power, and
- the amount of land potentially required for large wind farms.

## 2-3 Fuel Cells

.1 Interest in fuel cell power plants arises mainly from their ability to use conventional fuels with much higher efficiency than conventional generation technologies, their modularity, and their good environmental performance.

.2 Fuel cells are a rapidly developing technology. Of the three major fuel cell types assessed in this report, only phosphoric acid fuel cells (PAFC) can be considered to be commercially available. Molten carbonate fuel cells (MCFC) are forecast to be commercially available by the period 1995 to 2000 and solid oxide fuel cells after the year 2000.

.3 Current fuel cell costs are high; however, significant cost reductions are forecast as the technology becomes commercial.

.4 This review estimates the current (1991) levelized unit energy cost (LUEC) of electricity produced by PAFC power plants to be in the range of 8.9 to 19.4 ¢/kWh. The projected year 2000 costs for PAFC correspond to a LUEC range of 6.4 to 14.1 ¢/kWh (1991 dollars). The projected year 2000 costs for MCFC and SOFC power plants correspond to LUEC ranges of 5.7 to 12.6 ¢/kWh and 6.1 to 14.6 ¢/kWh, respectively.

.5 These costs indicate that fuel cell power plants are not currently economic for the production of electricity for the bulk electricity system in Ontario if the plants are used for electricity production only.

.6 Fuel cell power plants will most likely first become cost-effective in combined heat and power applications. The sale of useable heat could partially offset electricity production costs for the fuel cell options assessed here, depending on the assumptions made about the value of the heat.

.7 Siting of fuel cell power plants should be possible almost anywhere because of their modularity, quiet operation and low emissions as well as their capability to serve the on-site energy needs of the customer.

.8 A mature fuel cells technology may provide further benefits to utilities. Factory manufactured and assembled packages could reduce power plant lead times; stringent in-plant quality control and testing could improve standardization and reduce construction costs and schedules. Along with modularization, these advantages should enhance planning flexibility for load matching and incremental capacity additions in utility applications while reducing capital exposure. Standardization in system emissions, could enable dramatic reductions in the uncertainties, schedules and costs of environmental and regulatory permitting processes.

.9 During the next 10 to 20 years natural gas will likely be the primary fuel of choice for fuel cell operation due to its ready availability, ease of use, and reasonable cost compared to other fuels.

.10 In the longer term coal gasifiers may also be used to derive syngas from coal to power fuel cells. This development is not expected until molten carbonate and solid oxide fuel cell technologies have reached technical and commercial maturity, likely after the year 2000. Coal gasifiers would be used in combination with large fuel cell power plants in a centralized generating facility.

.11 The solid polymer fuel cell may also be of interest for off-grid applications because of its low temperature operation, its relatively compact and robust design, and the use of an easily transportable liquid fuel such as methanol.

.12 Technical issues that could prevent widespread implementation of fuel cells include less than predicted lifetime of fuel cell stacks (e.g., higher than predicted degradation of performance), and insufficient market development to enable economies of scale to apply to the manufacturing processes to bring the costs down to a point that the technology would be in demand. The operation of demonstration plants including the 200 kW PAFC plants, the 11 MW PAFC plant being operated in Japan and early demonstration units of both MCFC and SOFC technologies will confirm or disprove the performance and potential of this technology.

.13 Currently, cost is an impediment to the widespread implementation of PAFC technology, while MCFC and SOFC technologies are not yet scaled up or proven in sizes of interest to the marketplace. Increasingly stringent environmental regulations are providing an opportunity for the implementation of this clean fossil-fuelled technology in areas such as California. In other jurisdictions such as Japan, where the cost of fuel and electricity is considerably higher than in Ontario, the high efficiency of these devices is an added benefit.

.14 Fuel cells are anticipated to have a higher degree of social acceptance because of the low environmental emissions, limited waste disposal problems, flexibility in use for heat and electricity production, minor siting concerns and minimized requirement for transmission lines.

.15 Use of natural gas as a fuel is well accepted by society. However, some sensitive groups may have safety concerns (i.e., explosions) about the conversion of natural gas and other fuels to hydrogen within the fuel cell in order to generate electricity.

.16 Fuel cells will create limited employment for trades with skills on par with those required by utilities. With incentives fuel cells will have the potential for creating increased provincial economic development opportunities.

.17 As discussed in Part 2, Chapter 3, Section 3-11, the potential contribution of fuel cell power plants to the electricity supply mix for Ontario could be as low as 1 MW by the year 2005 to as high as 800 MW by the year 2014 depending on costs and technological developments.

.18 The advantages of fuel cell technology include:

- high energy conversion efficiency,
- siting flexibility,
- modularity, and
- low emission levels.

.19 Barriers to large-scale implementation of fuel cell technology include:

- high capital costs, and
- limited experience with the technology.

## 2-4 Biomass

.1 Biomass fuels have the following advantages over the use of conventional fossil fuels for electricity generation:

- biomass is a renewable resource, when properly managed,
- biomass is a low sulphur fuel and is considered to be carbon dioxide neutral, and
- biomass is low in ash and the ash could be returned to the forest or plantation.

.2 The technology for processing biomass fuels and for power generation from biomass has been proven in plant sizes up to 50 MW. Plant sizes up to 75 MW may be possible using conventional technology including fluidized bed combustion technology. Fluidized beds offer better $NO_x$ control. Biomass IGCC systems are reported to be in the pilot plant stage. If successfully scaled-up, these plants would increase the fuel utilization efficiency and reduce the capital costs of biomass-fuelled electricity generation.

.3 Ongoing research in several countries, including Canada, aims at developing biomass species suitable for energy plantations. Success in this area could lead to reduced costs for biomass fuels for electrical generation. Development of biomass fuels would require institutional changes in Ontario's forestry and agricultural industries.

.4 Cost is the major factor limiting the replacement of fossil fuels by biomass. Fuel costs are high, except in the case of waste wood. Because of the lower energy density of the fuel, biomass-fuelled generating stations are larger, and thus of higher capital cost, than fossil-fuelled generating stations of equivalent capacity.

.5 This review estimates the current levelized unit energy cost (LUEC) of electricity produced by plantation biomass-fuelled power plants to be in the range of 6.3 to 21.4 ¢/kWh. These costs indicate that plantation biomass-fuelled power plants are not currently economic for the production of electricity for the bulk electricity system in Ontario, if the plants are used for electricity production only.

.6 Biomass power plants could become economical sources of electricity generation when fuelled with waste biomass if the fuel is available free of charge or at negative cost. Waste biomass is used in Ontario as a source of fuel for electricity generation but is available in limited quantities. Biomass power plants also become more economic when installed in combined heat and power applications. The sale of useable heat could partially offset electricity production costs.

.7 Plants powered by biomass must be located relatively close to the fuel source (plantation or waste) because of the otherwise prohibitive costs associated with transporting the low energy density fuel.

.8 As discussed in Part 2, Chapter 4, Section 4-11, the potential contribution of biomass-fuelled power plants to the electricity supply mix in Ontario (in addition to capacity currently installed) could be another 100 MW by the year 2005, if only waste biomass is utilized. Biomass-fuelled capacity could increase by a further 100 MW by the year 2014, if plantation biomass becomes viable and costs decline.

.9 Biomass-fuelled generating facilities might provide local economic stimulus but the potential exists for localized community impacts. Changes in current institutions and practices within Ontario's forestry and agriculture sectors would be required to support the adoption of biomass waste gathering processes, sustained yield forests, and sustainable plantations and/or agricultural activities.

.10 In summary, the advantages of biomass as a fuel for electricity generation include:

- renewable resource, when properly managed,
- lower emissions of sulphur dioxide than fossil-fuelled generation,
- potential to be carbon dioxide neutral, and
- low in ash and the ash could be returned to the forest or plantation.

.11 The current barriers to wide scale introduction of plantation biomass-fuelled electricity generation in Ontario include:

- high capital cost of the plant,
- limited supplies of biomass waste,
- anticipated high cost of plantation-grown fuel production and transportation,
- significant land requirements for the plantations, and
- relatively low thermal efficiencies of existing biomass combustion technologies.

### 2-5 Peat

.1 Peat is a significant resource indigenous to Ontario.

.2 Peat has been used extensively as a fuel for electricity generation in Ireland and Finland, sometimes co-fired with other fuels such as wood and coal. Milled peat is the most common form of the fuel. The technology for the dry mining of peat is proven.

.3 The use of peat in North America has been, and continues to be, mainly horticultural.

.4 In the late 1970s and early 1980s there was considerable interest in peat-firing in Canada due to the high cost of oil. Since oil prices have dropped, much of the interest in the use of Canadian peat has declined. Peat remains a less economic fuel than oil, gas and coal.

.5 In 1986 the National Research Council reported that as an energy commodity the short and medium-term prospects for peat were not encouraging. Energy related considerations have not changed significantly since that time.

.6 Cost is a major factor limiting the replacement of fossil fuels by peat. Peat is more costly than oil, gas and coal because of its lower energy density and high cost of dewatering. Peat-fuelled plants are physically larger, and of higher capital costs, than fossil-fuelled plants of equivalent capacity.

.7 This review estimates that the current levelized unit energy cost (LUEC) of electricity produced by peat power plants fuelled with milled peat will be in the range of 9.4 ¢/kWh to 29.0 ¢/kWh. These costs indicate that peat-fuelled power plants are not currently economic for the production of electricity for the bulk electricity system in Ontario.

.8 Ontario peat is a very dispersed resource. Vast areas of bog are either altogether inaccessible, or contain very shallow deposits of peat which are uneconomic for mining, or the bogs cannot be drained for dry mining purposes. A few such areas could be mined if cost-effective wet-mining and slurry dewatering technologies are successfully developed.

.9 If Ontario's peat fuel resources are to be developed, wet mining techniques may prove more cost-effective for small separated bogs, and are less dependent on seasonal climatic conditions.

.10 Peat-fuelled generating stations would have to be located close to the source of the peat to avoid prohibitive transportation costs.

.11 Peat burning produces lower $SO_2$ emissions than does coal combustion. $CO_2$ emissions are, however, approximately 30 percent higher than those from a coal-fired plant of equivalent electrical capacity. Possible environmental concerns associated with peat extraction would need to be addressed.

.12 Ontario's peat deposits are located primarily in the northern and southeastern parts of the province and they cover some 16 million hectares. If less than 2 percent of those peat resources were used they could potentially support about 5000 MW of generating capacity over 30 years. As discussed in Part 2, Chapter 5, Section 5-11, the potential contribution of peat-fuelled power plants to Ontario's electricity supply mix could be in the order of 20 MW by the year 2005 and as high as 100 MW by the year 2014.

.13 Peat-fuelled generating facilities would likely be situated in northern or eastern Ontario. In such instances, peat-fuelled facilities could provide local economic stimulus. However, in the case of dry mining, positive long term employment benefits may be offset by the seasonal nature of the peat workforce. The potential exists for localized community impacts (e.g., increased access, traffic, dust, odour and noise) during construction or operations activities. Significant social concerns may also exist regarding non-renewability, ecosystem disruption and $CO_2$ emissions.

.14 Advantages of peat as a fuel for electricity generation include:

- indigenous fuel, and
- low sulphur dioxide emissions.

.15 Barriers to wide-scale introduction of peat-fuelled electricity generation in Ontario include:

- high cost of fuel production and transportation,
- high capital cost of the generating plant, and
- possible environmental concerns about peat extraction and fuel preparation, $CO_2$ emissions and non-renewability.

## 2-6 Municipal Solid Waste

.1 Municipal solid waste (MSW) has been developed as a fuel for electricity generation because of the opportunity to reduce the volumes of waste by means of incineration and to make use of a low or negative cost fuel.

.2 The technology for generating electricity from MSW is well established and used in many parts of the world. Development of equipment and processes to meet progressively stricter environmental requirements is ongoing.

.3 Forms of MSW fuel include unsorted and partially sorted waste (mass-burn technology), the gas generated by the anaerobic decomposition of waste in landfill sites (landfill gas), and fuels derived from the processing of waste (refuse derived fuel – RDF).

.4 Although RDF has a higher heating value than unsorted MSW, an RDF separating and combustion facility costs more than a mass burn plant of equivalent capacity and yields less electrical energy due to higher station service power requirements. RDF can be co-fired with a fossil fuel. However, uncertainties regarding waste content require that stringent emission controls be added to a converted fossil-fuel burning facility.

.5 From a purely cost perspective the burning of MSW would be an economical method of generating electricity in Ontario given the tipping fees in force in the Greater Toronto Area. The availability of fuel at negative or low cost makes electricity production a revenue producing byproduct of the MSW facility. As indicated in Part 2, Chapter 6, Section 6-10, electricity production could be economical at much lower tipping fees than currently exist in Metropolitan Toronto. The use of MSW plants in combined heat and power applications would make them more economical.

.6 Municipal solid waste fuel is a limited resource which can be consumed at more or less the rate at which it is produced.

.7 Energy-from-waste facilities tend to be close to larger population centres where the electrical energy will find use. The generating plant is usually tied into the electrical grid. There is little potential for energy-from-waste in off-grid applications.

.8 Energy-from-waste facilities would produce base load energy in most cases because landfill gas recovery is constant and large refuse burning facilities are operated around the clock to minimize corrosion of flue gas cleaning systems.

.9 As discussed in Part 2, Chapter 6, Section 6-11, potential generation of electric power from existing landfill gas sites in Ontario is estimated to be 30 MW. This potential is expected to increase to 60 to 70 MW by the year 2005. These resources are being utilized by private developers who make use of an energy resource that would otherwise be flared for safety and odour suppression reasons.

.10 For some MSW technologies, emissions controls and the disposal of ash as a hazardous material would be required.

.11 Local community impacts such as increased traffic, noise, dust, odour and concerns about property values may arise from the implementation of large scale MSW facilities. On a regional basis, social acceptance of MSW may be higher, given the potential for reducing the volume of waste going directly into landfills.

.12 The major barrier to implementation of MSW mass burn facilities is public acceptance of the potential environmental impacts of MSW incineration systems. The Ontario provincial government announced in 1991 that it would not approve new MSW incineration facilities.

.13 Assuming that 50 percent of garbage is recycled, currently it would be possible to generate up to 145 MW of electric power by mass burning refuse from the Greater Toronto Area. As discussed in Part 2, Chapter 6, Section 6-11, the potential contribution of MSW incineration plants to the electricity supply mix in Ontario, assuming provincial government approval and some increase in the total amount of garbage production, could be as high as 200 MW by the year 2014.

.14 Advantages of MSW as a fuel for electricity generation include:

- the renewable and indigenous nature of the fuel,
- reduction of waste volume, and
- use of an otherwise wasted resource.

.15 Barriers to wide-scale introduction of MSW-fuelled energy recovery systems in Ontario include:

- limited resource,
- lack of public acceptance,
- government policy, and
- low tipping fees outside the Greater Toronto Area.

## 2-7 Implications for Planning

.1 This assessment of six alternative technologies and their potential contribution to Ontario's electricity supply mix by the year 2014 indicates an increase over the assessment contained in the Demand/Supply Plan. These new estimates are being adopted for planning purposes.

.2 Potential contributions from these technologies, even if they prove to be greater than estimated in this review, would still be relatively small compared to the amount of new demand/supply options which would be needed as identified in the Demand/Supply Plan.

.3 With the exception of the burning of municipal solid waste, cost continues to be a significant barrier to utility-scale applications of alternative energy technologies in Ontario. However, private individuals and corporations (non-utility generators) may adopt some of these technologies, in the absence of access to the electricity grid, for cogeneration applications, or for demonstration purposes. It is expected that non-utility generators will continue to assess these and other technologies and will come forward with proposals to implement capacity when and if these options become economically attractive.

.4 Ontario Hydro continues to be involved in research and development concerning many generation concepts which have promising applications.

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## A-1 Corporate Environmental Policy, Principles and Strategy

.1 Ontario Hydro's existing Corporate Policy on the Environment has the following governing principle:

"Ontario Hydro shall seek to manage all activities which affect the environment such that the Ontario community receives the greatest overall net benefit in the long term."

.2 The existing Corporate Policy on the Environment, was developed in the 1970s, and is being revised. In 1990, a framework was developed to finalize Ontario Hydro's Environmental Principles, which were drafted in 1989. The Principles will express fundamental values on environmental leadership, decision making, wise resource use, consultation and responsibility. The framework provides a basis for a green paper to be issued in 1991.

.3 Ontario Hydro follows three basic emission control principles, listed below in order of preference:

- *Elimination:* The first environmental control principle is to eliminate emissions where practical. This can be accomplished through the selection of processes which avoid waste production, or by the use of zero-discharge or recycling systems.
- *Reduction:* Where emissions are unavoidable and wastes are not persistent or acutely toxic, the second principle is to reduce them to levels acceptable to society. Such levels are generally established by environmental regulations and Ontario Hydro standards.
- *Dilution:* For residual discharges of treated effluents, the third principle is to apply sufficient dilution or initial mixing to ensure the local environment is protected (e.g., heat dilution using sufficient cooling water). This is the least preferred approach to managing discharges.

## A-2 Environmental Planning and Assessment

.1 Ontario Hydro's activities are subject to the provincial Environmental Assessment Act. Depending on the type and scale of the project, the corporation's activities fall under one of four categories – full EA, class EA, review before exemption, or exemption.

.2 The EA process is also addressed at the federal level of jurisdiction. In 1990, the federal Environmental Assessment and Review Process (EARP) Guidelines were applicable. There are limited provisions to address projects concurrently under both federal and provincial jurisdictions.

.3 Several changes have been proposed regarding the provincial and federal EA processes, including the Provincial Environmental Assessment Program Improvement Project (EAPIP), the federal Bill C-78 and Canada's Green Plan. Many of the initiatives in these proposals address the need to streamline the EA process and avoid duplicated effort between federal and provincial jurisdictions.

## A-3 Environmental Regulations

.1 Ontario Hydro's activities are subject to a wide range of environmental regulations. While most of the legislation is provincial, federal authorities also have jurisdiction. Projects sited on federal lands, co-funded by federal agencies, or having a federal interest, require federal environmental review and/or approval in addition to provincial approvals.

.2 A variety of federal and provincial statutes require permits or licenses for the construction and operation of facilities. Most permit requirements fall under the Ontario Environmental Protection Act (EPA) and the Ontario Water Resources Act (OWRA). Substantial reporting is required to demonstrate compliance with permit requirements.

.3 The Ministry of the Environment put the Municipal Industrial Strategy for Abatement (MISA) monitoring program into effect in 1989. The goal of MISA is the elimination of discharges of persistent, toxic chemicals to Ontario waterways. The province will set emission limits based on the monitoring results, and the best available control technology that is economically achievable (BACTEA).

.4 In addition to the ongoing implementation of MISA, several other regulatory changes relevant to control technologies have recently been approved or are under consideration.

- In August 1990, the Ontario Ministry of the Environment issued the Clean Air Program (CAP) as a draft regulation for a 180 day comment period. The goal of CAP is the virtual elimination of air toxics (analogous to MISA for effluents to waterways). Pollutants are ranked according to level of concern. In order to meet the goal, CAP requires appropriate control equipment to meet specific emission limits, and controls matched to the level of hazard posed by the contaminant.

- In 1988, the Canadian Council of Ministers of the Environment (CCME) requested a plan to reduce ground level ozone levels by controlling nitrogen oxides and volatile organic compounds. Discussions are ongoing regarding $NO_x$ targets, schedules and control options. The draft plan requires more stringent emission limits for $NO_x$ emissions from utilities across Canada, particularly in the Windsor/Quebec City corridor.

- The U.S. Clean Air Amendments Act was enacted in November 1990. The Act phases in reductions of $SO_2$ and $NO_x$ emissions in the United States. This Act may influence evolving Canadian regulations.

## B-1 Introduction

.1 Three of the concepts discussed in Part 2, Technology Assessments, involve combustion of a fuel (biomass, peat or municipal solid waste) to produce thermal energy to drive a heat engine which powers an electricity generator.

.2 The technologies available for the combustion of these fuels, referred to in this appendix as thermal generation concepts, have much in common. They are also similar to technologies widely used with fossil fuels such as coal, oil and natural gas.

.3 A second set of technologies, referred to in this appendix as environmental control concepts, deals with processes which reduce the environmental impact of combustion based power generation.

.4 The purpose of this appendix is to describe and discuss available fuel combustion and available emission control technologies. In addition, fuel transportation issues that are generic to the use of biomass, peat and MSW for electricity generation are discussed in this appendix.

## B-2 Thermal Generation Concepts

### B-2-1 General

.1 The purpose of this section is to describe the combustion and electricity generation processes considered in this report.

.2 There are many thermal generation options. In developing a practical list of concepts, the following were considered:

- available generation technologies,
- different fuels, such as coal, oil, natural gas, lignite, biomass, peat and municipal solid waste, and
- the different development states of technologies which range from unproven to mature.

.3 The thermal generation concepts considered are:

- steam electric systems,
- gas electric systems (combustion turbine units (CTUs)),
- CTU combined cycle systems, and
- cogeneration systems (i.e., the simultaneous production of electricity and useable heat).

.4 Figure B-2-1-1 illustrates the types of fuels which may be used with these generation concepts.

***Figure B-2-1-1: Thermal Generation Concepts – Fuel Acceptability***

| Concept | Fuel State | | |
|---|---|---|---|
| | Gaseous | Liquid | Solid |
| Conventional Steam Cycle | X | X | X |
| Combustion Turbine Unit (CTU) | X | X | |
| CTU Combined Cycle | X | X | |
| Cogeneration Cycle | X | X | X |

.5 Brief descriptions of the four principal thermal generation concepts are included in the following sections.

### B-2-2 Conventional Steam Cycle

*System Description*

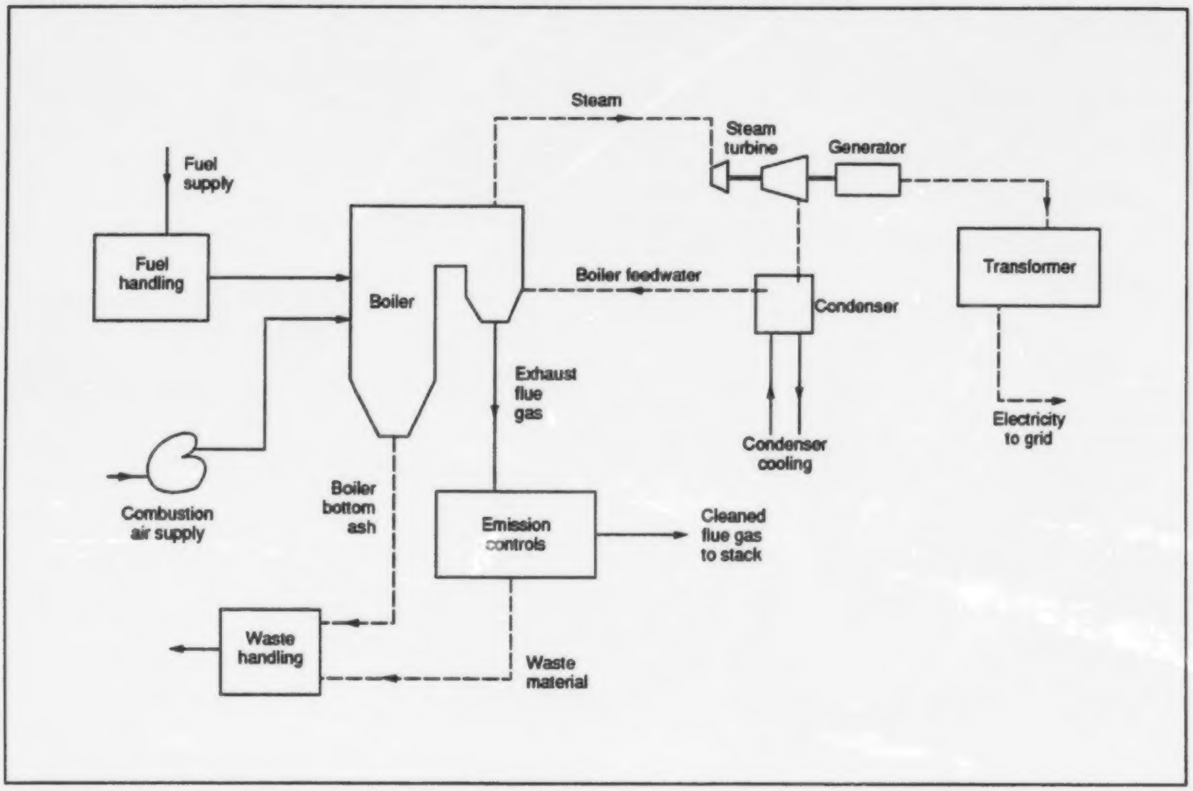
.1 Conventional steam cycle units are considered for the purposes of this review to be those between approximately 15 and 800 MW net output.

.2 Figure B-2-2-1 illustrates the six basic components of a conventional steam cycle unit consisting of:

- fuel handling,
- boiler,
- steam turbine-generator,
- transformer,
- environmental controls, and
- waste handling.

.3 Fuel handling is the first step in the power generation process. Fuel in either gaseous, liquid or solid form is passed through any or all of the following steps: receipt, storage, retrieval, forwarding to short term storage in the plant, fuel processing, and input to the boiler. Fuel from the fuel handling system may or may not require further processing, such as pulverizing or drying.

*Figure B-2-2-1: Conventional Steam Cycle – Block Diagram [Ontario Hydro (OH), 1989]*


Steam
Steam turbine
Generator
Fuel supply
Fuel handling
Boiler
Boiler feedwater
Condenser
Transformer
Exhaust flue gas
Electricity to grid
Condenser cooling
Combustion air supply
Boiler bottom ash
Emission controls
Cleaned flue gas to stack
Waste handling
Waste material

.4 Combustion of the fuel in the boiler is the second step in the power generation process. The fuel is fed to the boiler. Boiler air intake fans supply air which is combined with the fuel in the burners or boiler where combustion takes place. The heat energy released by the combustion of the fuel is transferred to water contained in banks of steel tubes within the boiler. This heat transfer converts the water in the tubes to high pressure steam.

.5 The steam turbine generator is the third step in the power generation process. The high pressure steam is expanded against the blades of a steam turbine, causing the turbine to rotate. The steam turbine in turn drives an attached generator which converts the turbine's mechanical energy into electrical energy.

.6 The transformer is the fourth step in the power generation process. The relatively low voltage electricity from the generator is stepped up to a higher voltage for delivery to the Bulk Electricity System (BES).

.7 Emission controls are integral parts of the power generation process. They reduce plant emissions to the environment. These controls remove solid, gaseous and liquid wastes and collect them for regulated disposal. The emission control equipment is designed to meet stringent regulatory requirements.

.8 The waste handling systems collect and transport wastes for disposal or use.

### *Combustion Technology Variations*

.9 There are many variations on the conventional steam system concept. The major variables are presented in Figure B-2-2-2. They exclude those variables attributable to environmental control concepts which are discussed in detail in Section B-3.

*Figure B-2-2-2: Conventional Steam System Variations*

| Variable | Type |
|---|---|
| Fuel | • Solid (e.g., coal, peat, wood, MSW)<br>• Liquid (e.g., oil)<br>• Gaseous (e.g., natural gas, landfill gas) |
| Pressure | • Subcritical (1800 to 2500 psi)<br>• Supercritical (3500 to 5000 psi) |
| Condenser Cooling | • Once-through cooling<br>• Cooling towers (wet or dry)<br>• Cooling ponds |
| Steam Generator | • Dutch Oven<br>• Spreader Stoker Stationary Pinhole Grate<br>• Spreader Stoker Travelling Grate<br>• Gravity Feed Inclined Grate<br>• Suspension-Fired<br>• Fluidized Bed Combustion |

.10 Any combination of fuel, pressure and condenser cooling is possible. Most utility fossil fuelled generation is of the conventional subcritical pressure type.

.11 Supercritical units operate at higher steam pressures and temperatures to achieve somewhat higher efficiencies for base load applications. However, they have higher capital costs and less operating flexibility. Supercritical technology is not cost effective for small unit sizes.

.12 Most of Hydro's fossil-fuelled stations are located on the Great Lakes. The once-through cooling system is the least costly approach to condenser cooling of large units. Large quantities of water are pumped into the condensers to cool and condense the exhaust steam from the steam turbines. This cooling water is warmed slightly and then returned to the lake. "Mine-mouth" conventional steam cycle stations may require the use of cooling towers, ponds or dry condensers.

.13 There are a number of different types of boilers which can be employed, the choice of which is dependant upon the size of the plant and the chemical and physical properties of the design fuel. The nature of the fuel also determines the fuel handling, waste handling and emission control equipment characteristics.

.14 Steam generator types that can be used to burn materials such as fossil fuels, biomass, peat, and municipal solid waste, include:

- Dutch oven furnace,
- spreader stoker stationary pinhole grate boiler,
- spreader stoker travelling grate boiler,
- gravity feed inclined grate boiler,
- suspension-fired boiler, and
- fluidized bed boiler.

.15 Figures B-2-2-3 to B-2-2-8 illustrate these furnace and boiler types.

*Figure B-2-2-3: Dutch Oven [Monenco Consultants Limited]*

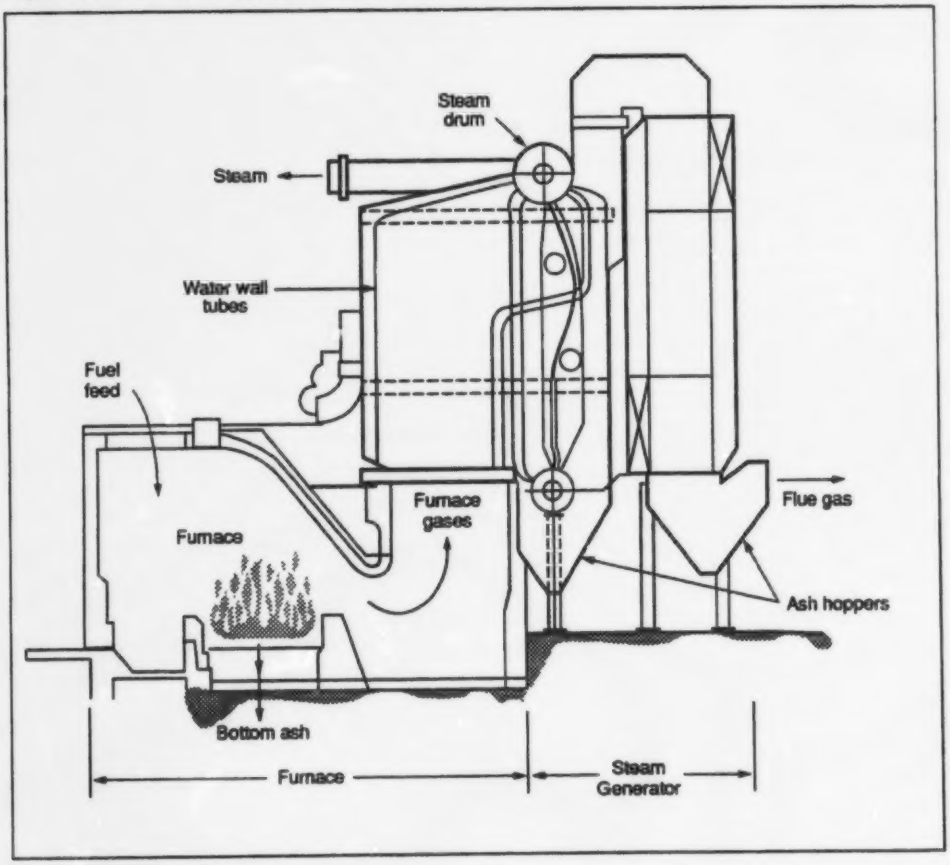

Steam drum
Steam
Water wall tubes
Fuel feed
Furnace
Furnace gases
Flue gas
Ash hoppers
Bottom ash
Furnace
Steam Generator

*Figure B-2-2-4: Spreader Stoker Pinhole Grate [Monenco Consultants Limited]*

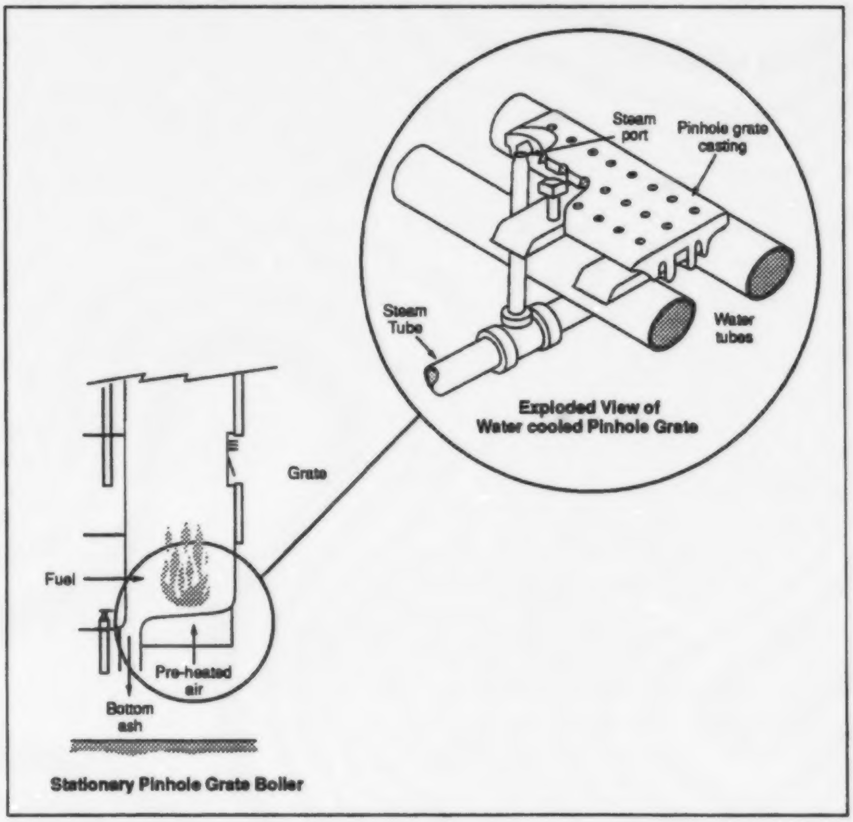
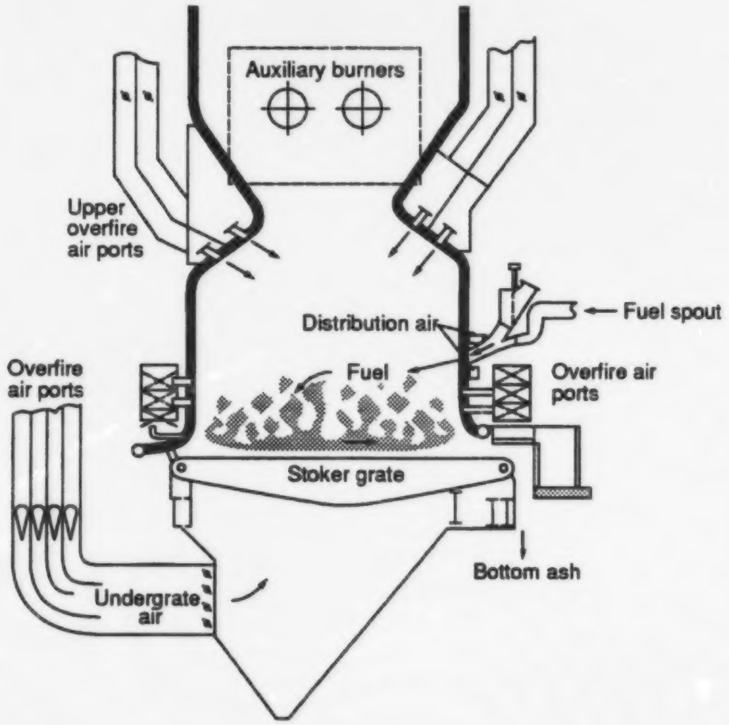

Steam port
Pinhole grate casting
Steam Tube
Water tubes
Exploded View of Water cooled Pinhole Grate
Grate
Fuel
Pre-heated air
Bottom ash
Stationary Pinhole Grate Boiler

*Figure B-2-2-5: Horizontal Stoker Travelling Grate*


Auxiliary burners
Upper overfire air ports
Fuel spout
Distribution air
Fuel
Overfire air ports
Overfire air ports
Stoker grate
Bottom ash
Undergrate air

Source: Alex Topley — Babcock & Wilcox Canada

*Figure B-2-2-6: Gravity Feed Inclined Grate*

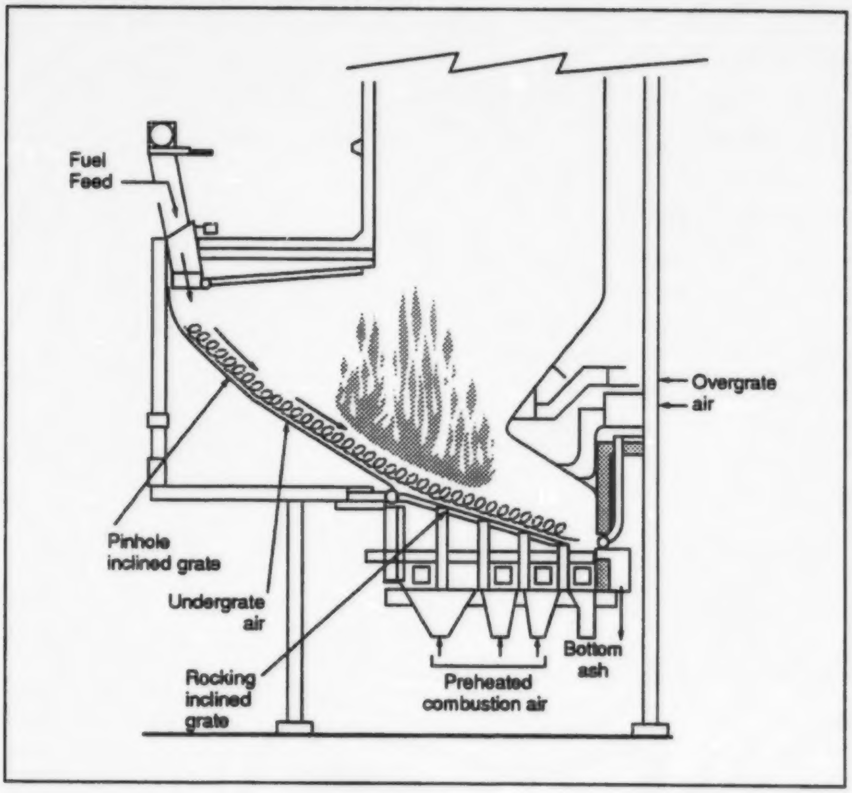

Fuel Feed
Overgrate air
Pinhole inclined grate
Undergrate air
Rocking inclined grate
Preheated combustion air
Bottom ash

*Figure B-2-2-7: Suspension Fired Boiler [Babcock & Wilcox, 1978]*

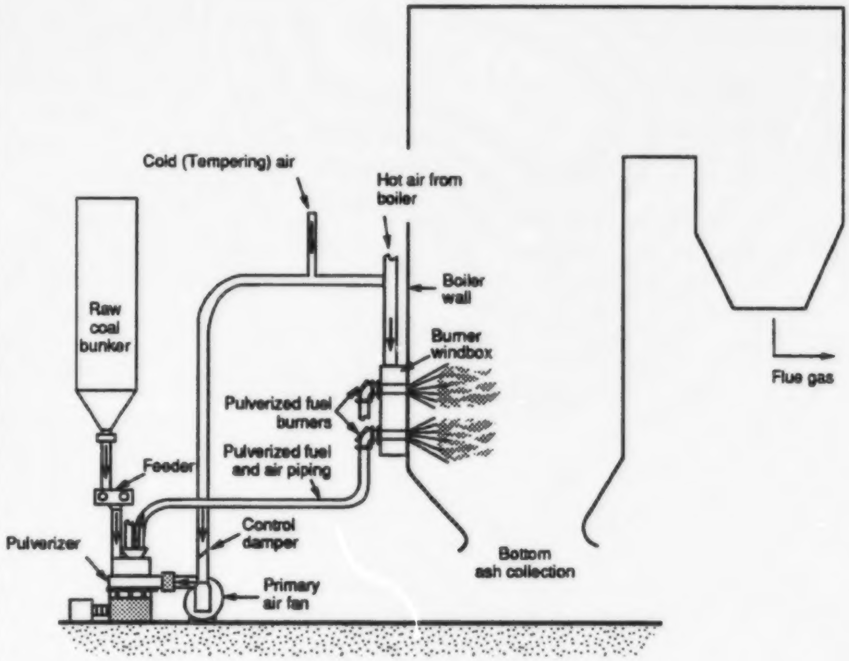
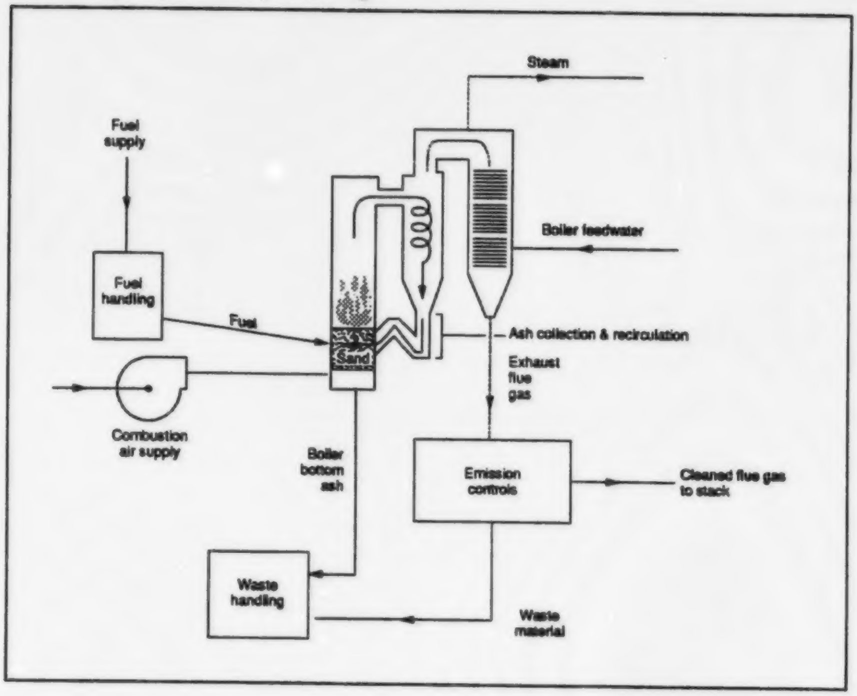

Cold (Tempering) air
Hot air from boiler
Boiler wall
Raw coal bunker
Burner windbox
Flue gas
Pulverized fuel burners
Pulverized fuel and air piping
Feeder
Control damper
Pulverizer
Bottom ash collection
Primary air fan

***Figure B-2-2-8: Circulating Fluidized Bed Combustion – Block Diagram [Ontario Hydro, 1989]***


Steam
Fuel supply
Boiler feedwater
Fuel handling
Fuel
Ash collection & recirculation
Sand
Exhaust flue gas
Combustion air supply
Boiler bottom ash
Emission controls
Cleaned flue gas to stack
Waste handling
Waste material

.16 Dutch ovens, which are now seldom built for electrical generation, are brick-lined furnaces into which fuel is fed by gravity. The hot gases from the oven pass into a second chamber where they are used to generate steam which can be used to drive a turbine-generator. Ash and clinkers on the furnace floor must periodically be removed through ash doors. However, fuel feed and ash removal can be automated, and sloping grates incorporated.

.17 A spreader stoker is a mechanical and pneumatic device which feeds the fuel and spreads it evenly on the grate for combustion.

.18 Grates and mechanical stoker systems allow closer control of air for combustion and simplify ash removal. These steam generators are generally constructed of one rather than two separate chambers, so that water tubes installed in the boiler walls can obtain the additional benefit of radiant heat from the combustion flame for the generation of steam. Grates are frequently water cooled. For reasons of thermal efficiency and automatic ash removal, grate firing-systems are preferred to dutch ovens.

.19 A stationary pinhole grate is a slightly sloping grate which is generally constructed of water tubes and iron alloy pinhole castings. The fuel is fed evenly onto the grate by spreader stokers. The smaller particles burn in suspension as the fuel is thrown onto the grate by the stoker, but most of the fuel burns on the grate. Preheated undergrate combustion air flows upward through the grate often at a slight angle so as to move the ash down the sloping grate. Jets of steam are also used to assist ash movement towards the ash pit. Periodically the grate must be cleaned out manually in order to keep the grate operating correctly.

.20 The most widely used types of grates are the horizontal travelling type and the inclined type. Both types are designed to first dry the fuel, initiate and complete combustion, and then remove the ash. In the first type the fuel bed moves with the travelling grate. In the second type the fuel bed gravitates down a stationary inclined grate. Air is introduced at different levels of the boiler to ensure complete combustion.

.21 Reasons for the popularity of these two systems include ability to handle a wide range of fuel particle sizes, and the movement of the fuel bed towards the ash pit so that ash removal can be automated.

.22 Suspension-fired boilers differ from the others in that pulverized solid fuels or liquid or gaseous fuels are blown into the boiler through several burners located at various positions in the boiler walls. Solid fuels are usually pulverized and sometimes dried in mills just prior to being blown into the boiler.

.23 The fluidized bed combustion (FBC) concept combines fuel and sand or limestone and three processes take place:

- fluidization,
- combustion, and when required,
- sulphur capture.

.24 The fluidization process involves blowing air up through a bed of sand and fuel (in the case of low sulphur fuels such as biomass and peat) or fuel and limestone (in the case of higher sulphur content coals or MSW). The air flow through the bed offsets the weight of the bed material and creates a motion similar to that in a pot of boiling water.

.25 The residence time of the fuel in the fluidized bed is considerably longer than for fuel in suspension-fired boilers allowing lower furnace temperatures, which in turn lower $NO_x$ production.

.26 FBC is a relatively flexible boiler technology which enhances the burning of low quality fuels and maximizes energy production. FBC is predominantly a solid fuel process which can tolerate fuel specifications that vary somewhat more than those for pulverized fuel boilers.

.27 FBC boilers are only commercially available and proven for sub-critical steam cycle applications. At this time, FBC systems do not generally exceed 150 MW in unit capacity.

.28 Further details on FBC technology can be found in the Thermal Cost Review. (TCR, 1989)

.29 The travelling grate, inclined grate, and fluidized bed boilers appear to be the most appropriate technologies for power generation from biomass, municipal solid waste, and sod peat. Suspension-fired boilers are widely used to burn milled peat.

## B-2-3 Gas-Electric Systems

### *General*

.1 Gas-electric systems such as combustion turbine units (CTU) range in size up to about 150 MW and may burn gaseous or liquid fuel.

.2 Figure B-2-3-1 illustrates the seven basic components of a gas-electric/combustion turbine unit, namely:

- fuel handling,
- compressor,
- combustion chamber,
- gas turbine,
- generator,
- transformer, and
- environmental controls.

.3 Fuel handling is the first step in the power generation process. Liquid fuel passes through the following steps: receipt, storage, retrieval, and input to the combustion chamber. Gaseous fuel usually goes directly to the combustion chamber.

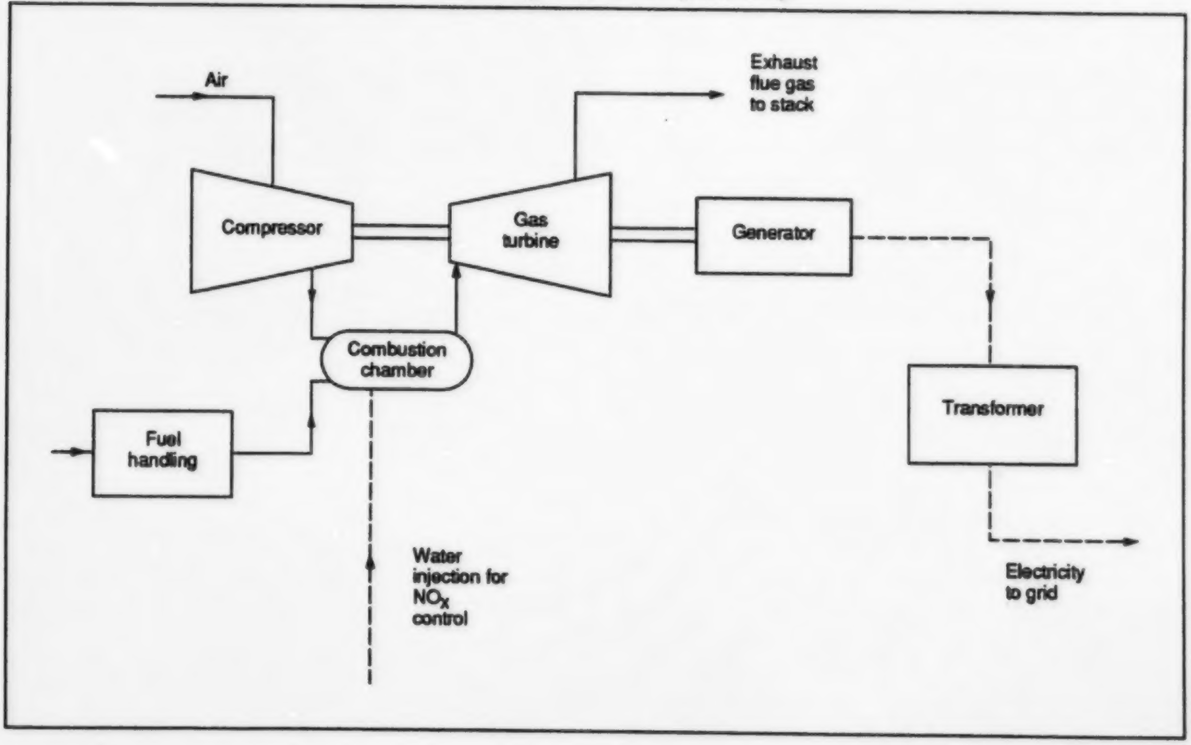
.4 The compressor supplies high pressure air to the combustion chamber. The air compressor is usually driven directly by the gas turbine.

.5 Fuel and air are mixed and burned in the combustion chamber and produce hot gases at temperatures between 900 and 1100°C.

.6 The high temperature gases from the combustion chamber expand through the gas turbine blades causing the turbine to rotate at high speed.

.7 The gas turbine drives its attached generator which converts the turbine's mechanical energy into electrical energy.

*Figure B-2-3-1: Combustion Turbine Unit – Block Diagram [Ontario Hydro, 1989]*


Air
Exhaust flue gas to stack
Compressor
Gas turbine
Generator
Combustion chamber
Transformer
Fuel handling
Water injection for $NO_x$ control
Electricity to grid

.8 The relatively low voltage electricity from the generator is stepped up by a transformer to a higher voltage for delivery to the Bulk Electricity System.

.9 Combustion turbine fuels usually have low sulphur content and environmental controls to reduce sulphur dioxide are not usually provided. However, nitrogen oxides are produced in the combustion chamber. Environmental controls may be installed to minimize $NO_x$ emissions.

*Concept Variations*

.10 There are many variations on the basic combustion turbine concept. The major variables are presented in Figure B-2-3-2.

***Figure B-2-3-2: Combustion Turbine Engines – Variations***

| Variable | Type |
|---|---|
| Fuel | • Gaseous (e.g., natural gas, landfill gas)<br>• Liquid (e.g., light oil)<br>• Dual fuel (e.g., natural gas or light oil)<br>• Solid (e.g., sawdust) * |
| Service | • Fast start<br>• Heavy duty |
| Maturity | • Conventional units, with long history of operation – up to 100 MW<br>• Advanced design, higher efficiency, little operating history – greater than 100 MW |

* Under development.

*Development Status*

.11 Most CTUs currently being used are designed to burn high energy, clean fuels such as natural gas and light oil. CTUs capable of burning low energy biogas or landfill gas are not widely available.

.12 CTUs designed to burn shredded biomass fuels are in early stages of development.

### B-2-4 CTU Combined Cycle Systems

*General*

.1 Combined cycle (CC) units consisting of a gas-electric topping cycle and a steam-electric bottoming cycle range in size up to 900 MW and burn liquid or gaseous fuels.

.2 Figure B-2-4-1 illustrates the six basic components of the combined cycle module which are:

- fuel handling,
- combustion turbine unit,
- heat recovery steam generator unit,
- steam-turbine generator,
- transformer, and
- environmental controls.

.3 Fuel handling is the first step in the power generation process. Liquid fuel passes through the following steps: receipt, storage, retrieval, and input to the combustion chamber. Gaseous fuel usually goes directly to the combustion chamber.

.4 The combustion turbine unit is described in Section B-2-3.

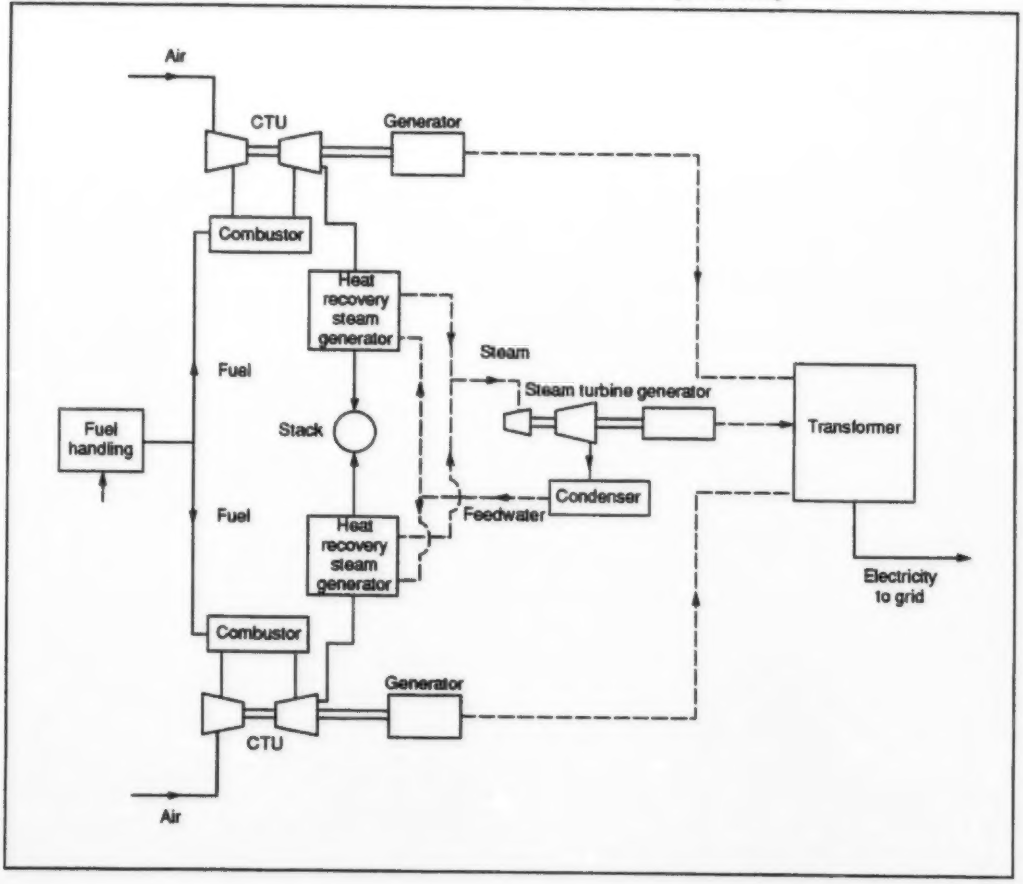
.5 The heat recovery steam generator (HRSG) is a heat exchanger which converts the thermal energy in the combustion turbine exhaust gas into steam for use in the steam turbine generator.

.6 The steam turbine generator converts the thermal energy in the steam from the HRSG into mechanical energy and ultimately into electrical energy.

.7 The transformer steps up the relatively low voltage electricity from the generators to a higher voltage for delivery to the Bulk Electricity System.

.8 The environmental controls for combined cycle are the same as those for the gas-electric/combustion turbines.

*Figure B-2-4-1: Combined Cycle Module – Block Diagram [Ontario Hydro, 1989]*


Air
CTU
Generator
Combustor
Heat recovery steam generator
Steam
Fuel
Steam turbine generator
Fuel handling
Stack
Transformer
Condenser
Feedwater
Fuel
Heat recovery steam generator
Electricity to grid
Combustor
Generator
CTU
Air

### *Technology Variations*

.9 There are many variations on the basic combined cycle concept. The major variables are presented in Figure B-2-4-2. They exclude those variables attributable to environmental control technologies which are discussed later in this appendix.

***Figure B-2-4-2: Combined Cycle Variations***

| Variable | Type |
|---|---|
| Fuel | • Gaseous (e.g., natural gas, landfill gas)<br>• Liquid (e.g., light oil)<br>• Dual Fuel (e.g., natural gas or oil) |
| HRSG Configuration | • With supplementary fuel<br>• Without supplementary fuel |
| CTU/Steam Turbine Co-figuration | • Separate CTU with matching steam turbine<br>• Single CTU and steam turbine driving a single generator on a common shaft<br>• Multiple CTUs per steam turbine |
| Maturity | • Conventional units, with long history of operation – up to 100 MW<br>• Advanced design, higher efficiency, little operating history – greater than 100 MW |

.10 Heat recovery steam generators for utility applications have traditionally not used supplementary fuel fired directly into the HRSG to increase power output as it has the disadvantage of decreasing the unit's efficiency.

.11 Combined cycle economy can be improved by using more than one CTU for each large steam turbine.

.12 Single shaft combined cycle modules have been developed and are currently in use. The gas turbine and the steam turbine are located on a single shaft in series with a single generator. This configuration reduces initial capital cost but limits overall unit flexibility.

## B-2-5 Cogeneration Systems

### *General*

.1 Cogeneration refers to the production of both useable heat and electricity. When fuel is burned to produce electricity, about 30 to 40 percent of the chemical energy of the fuel is converted to electrical energy. The balance of the fuel energy is dissipated to the environment. Cogeneration systems utilize between 50 and 80 percent of fuel energy by salvaging some of the fuel energy, which would otherwise be wasted, and channelling it to useful end-uses in process or space heating.

.2 Virtually all industrial, institutional, and commercial facilities utilize thermal and electrical energy. To meet their thermal demand most facilities produce heat on-site in the form of steam or hot water from a supplied fuel source. Electricity, on the other hand, is usually purchased from an off-site electrical utility.

.3 The greatest potential for cogeneration applications exist in industrial facilities with continuous thermal and electric power requirements. Such industries include producers of pulp and paper, textiles, steel, food and chemicals.

.4 Large commercial and multi-unit residential buildings may also derive substantial benefits from cogeneration.

.5 Cogeneration technology is proven and is being used in Ontario. (Ontario Ministry of Energy, 1988)

.6 In Ontario typical fuel sources for cogeneration include natural gas, diesel oil, waste biomass and black liquor.

.7 Overall fuel energy conversion efficiency ranges between 55 and 80 percent and is the sum of the thermal recovery and electrical conversion efficiencies of a cogeneration system.

.8 Thermal recovery efficiency refers to the proportion of total fuel energy recovered as heat. This range is typically between 20 to 50 percent.

.9 Electrical conversion efficiency is the proportion of total fuel energy converted into electrical energy. It can range between 15 and 45 percent, depending on the fuel and technology used.

.10 The major benefit of cogeneration is that it offers the potential for achieving substantial energy cost savings. The overall conversion efficiency of conventional power generating systems which reject heat directly into the environment typically ranges from about 30 to 40 percent.

.11 Potential revenues can also be realized from the sale of electricity to utilities or from surplus steam and hot water sold to neighbouring users.

.12 In summary, cogeneration can provide many potential benefits such as energy cost savings, improved reliability of electrical energy supply in the form of standby power, and enhanced process flexibility.

### *Technology Variations*

.13 There are two principal types of cogeneration systems or "operating cycles", which depend on whether mechanical/electric power is produced before or after heat is extracted for thermal application.

.14 The system in which electric power is produced first, followed by the extraction of heat, is known as a "topping cycle" and is illustrated in Figure B-2-5-1. This is the most common type of cogeneration system.

.15 Prime movers typically used in topping cycle systems include reciprocating engines (gas and diesel) and gas turbines. After electricity is generated, the combustion exhaust gas is sent to a heat-recovery boiler which produces hot water or steam. In the case of engines, heat is also recovered from the jacket water cooling circuit, and this heat represents the dominant contribution.

.16 The second type of cogeneration system uses a high pressure steam boiler and a steam turbine driven generator in a "bottoming cycle".

.17 In this configuration high-temperature steam or hot water is first produced in a boiler primarily for thermal application. As illustrated in Figure B-2-5-2, the residual steam or hot water is then used to drive a steam turbine to generate electricity.

.18 While a bottoming cycle system is highly efficient because no additional fuels are required to produce electricity, its application is limited to situations with relatively high-temperature thermal requirements.

***Figure B-2-5-1: Schematic of a Gas-Turbine Topping Cycle Cogeneration System [Ontario Ministry of Energy, 1988]***

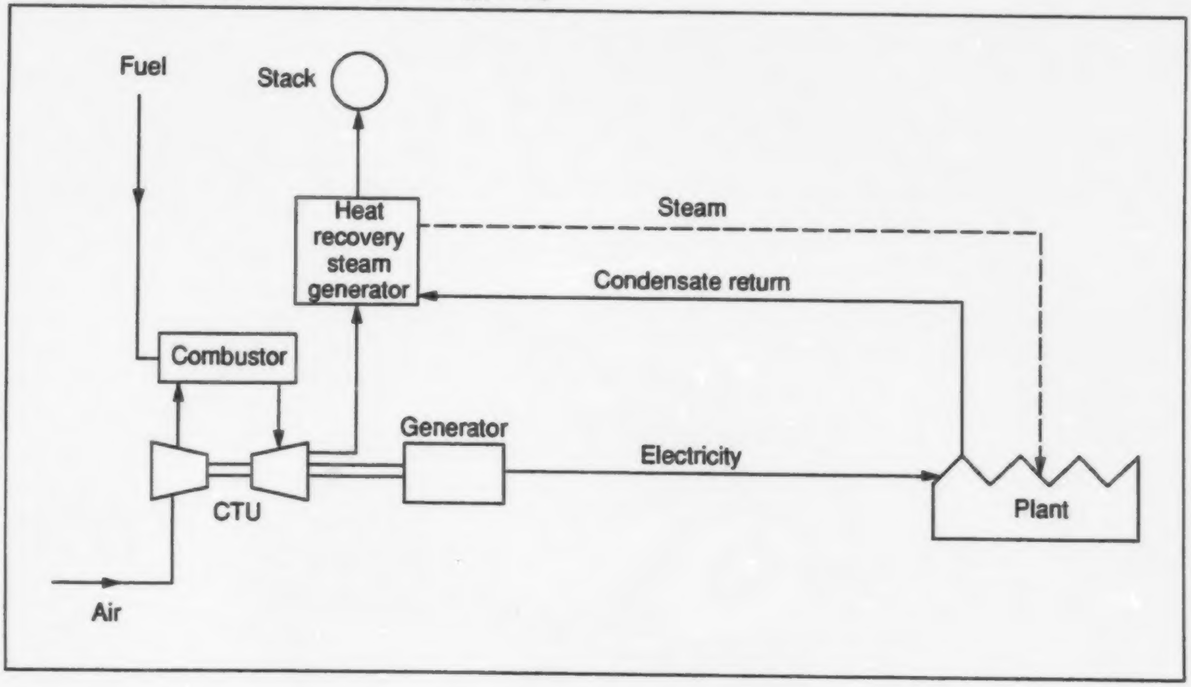
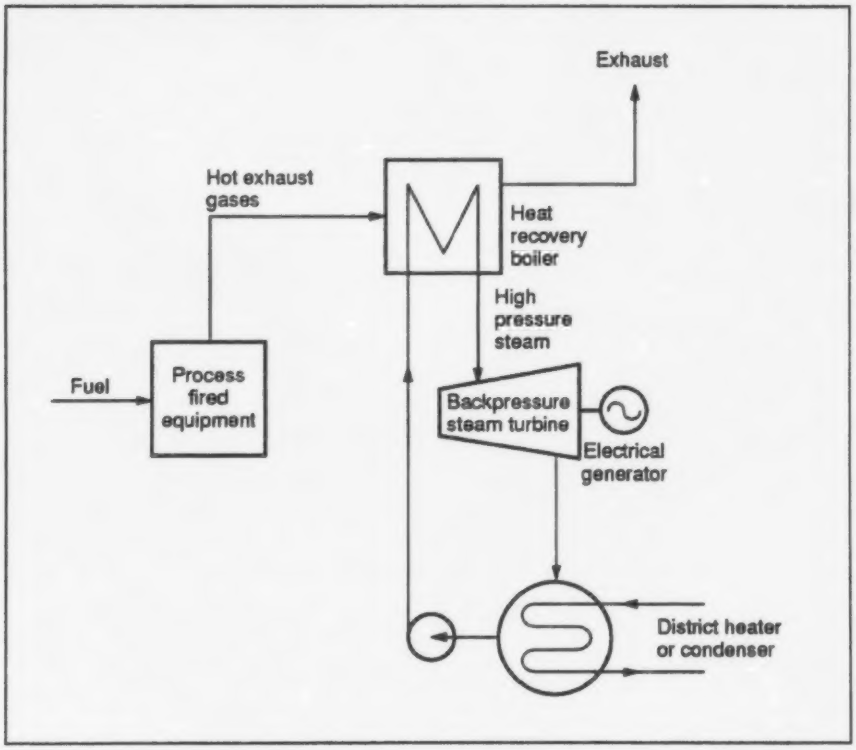


*Figure B-2-5-2: Schematic of a Steam Turbine Bottoming Cycle Cogeneration System [Monenco Consulting Limited]*


Exhaust
Hot exhaust gases
Heat recovery boiler
High pressure steam
Fuel
Process fired equipment
Backpressure steam turbine
Electrical generator
District heater or condenser

## B-3 Emission Control Concepts

### B-3-1 General

.1 As with the generation concepts there are many possible environmental control concepts for thermal generation. The combustion of biomass, peat or MSW to produce electricity may require emission controls to reduce emissions to the environment.

.2 In developing a practical list of concepts Hydro considered the following:

- current and proposed environmental regulations in Ontario and Ontario Hydro's environmental performance targets,
- the available environmental control technologies,
- the different fuels, such as coal, oil, natural gas, lignite, biomass, peat and municipal solid waste, and
- the different development states of technologies which range from unproven to mature.

.3 Figure B-3-1 shows the various emission control concepts which may be used with the different fuel states. These concepts are sufficiently proven and economic for further consideration.

.4 In order of applicability to the greatest number of alternate energy technologies, the environmental control concepts described in this section of the chapter are:

- particulate emission controls,
- $NO_x$ emission controls, and
- other acid gas emission controls (e.g., $SO_2$).

.5 These control technologies can also be used in combination to control emissions of metals and toxins.

.6 There are no commercially available processes for reducing emissions of $CO_2$.

*Figure B-3-1: Emission Control Concepts for Various States of Fuel*

| Concept | Fuel State | | |
|---|---|---|---|
| | Gaseous | Liquid | Solid |
| **Particulate Reduction** | | | |
| • Cyclones | | X | X |
| • Wet Scrubbers | | X | X |
| • Electrostatic Precipitators | | X | X |
| • Baghouse Fabric Filters | | X | X |
| **Nitrogen Oxides (NO, $NO_2$) Reduction** | | | |
| • Combustion Controls (Low $NO_x$ Burners) | X | X | X |
| • Ammonia/Urea Injection | X | X | |
| • Steam/Water Injection | X | X | X |
| • Selective Catalytic Reduction | X | X | X |
| **Sulphur Dioxide ($SO_2$)/Other Acid Gas Reduction** | | | |
| • Limestone Slurry | | X | X |
| • Lime Spray Dryer FGD | | X | X |
| • Limestone Dual Alkali FGD | | X | X |

### B-3-2 Particulate Reduction

*General*

.1 Most fuels contain non-combustible material known as ash.

.2 Figure B-3-2 shows typical ash contents for various fuels.

.3 When fuel is burned part of the ash is removed from the bottom of the boiler and is called bottom ash. The remaining ash, fly ash, appears as a very fine particulate material in the flue gas.

.4 Particulate emissions in the flue gas are objectionable because they:

- contribute to respiratory problems,
- contribute to fog and smog,
- deposit in local communities, and
- in the case of MSW, carry metals and possibly toxins.

.5 Particulate emission controls are used to remove most of the fly ash from the flue gas to meet regulatory requirements. Ontario Hydro installs particulate emission control devices in its fossil-fuelled units. This equipment is installed between the furnace and the stack and typically removes over 98 percent of the particulate.

.6 Fly ash may be used as landfill or it may require specialized disposal. Ontario Hydro has been able to sell some coal fly ash to the cement industry. Fly ash from fuels such as biomass may have other commercial uses.

.7 Particulate control devices are very large and expensive because of the large volume of flue gas which has to be treated.

.8 There are several types of particulate control devices which can be used in boiler applications. These include:

- cyclones (mechanical separator devices),
- wet scrubbers,
- electrostatic precipitators (ESPs), and
- fabric filter baghouses.

.9 Cyclones and wet scrubbers have been used on smaller boiler systems fuelled with wood.

.10 Typically, electrostatic precipitators and fabric filter baghouses have been used for particulate removal in utility boiler applications.

***Figure B-3-2: Typical Fuel Characteristics of Various Fuels***

| | Heavy Fuel Oil | Coal (bituminous) | Lignite | Peat | Wood |
|---|---|---|---|---|---|
| C % | 83–86 | 76–87 | 65–75 | 50–60 | 48–50 |
| H % | 11.5–12.5 | 3.5–5.0 | 4.5–5.5 | 5.0–6.5 | 6.0–6.5 |
| O % | 1.5–2.5 | 2.8–11.3 | 20–30 | 30–40 | 38–42 |
| N % | 0.2–0.3 | 0.8–1.2 | 1–2 | 1.0–2.5 | 0.5–2.3 |
| S % | 2.0–2.8 | 1.0–3.0 | 1–3 | 0.1–0.2 | <0.1 |
| Ash Content % | 0.3 | 4–10 | 6–10 | 2–10 | 0.4–0.6 |
| Volatiles % | | 10–50 | 50–60 | 60–70 | 75–85 |
| Bulk density kg/m$^3$ | 920–970 | 720–880 | 650–780 | 100–400 | 320–420 |
| Operational moisture % | 0.1 | 3–8 | 40–60 | 40–60 | 30–55 |

### *Cyclones*

.11 Single cyclones and multicyclones are mechanical separators which use centrifugal forces to separate and remove particulates which have been entrained in flue gas streams emerging from boilers. The gas stream entering the cylinder of a cyclone is forced into a high speed vortex which throws the entrained particles against the wall of the cylinder where they are collected. The gas exits the cylinder upward through a central passage.

.12 Cyclone separators have the following performance characteristics:

- They remove heavier particles more effectively than lighter particles. The latter escape collection by remaining entrained in the gas stream.
- They are more efficient when the radius of the cyclone cylinder is small. This accounts for the preference for using several small diameter cyclones (multicyclones) in place of one large diameter.
- They are more efficient when the gas velocity in the cyclone is high. This requires parallel multicyclone banks to minimize pressure drop and fan power requirements.
- Multicyclones are the least expensive of the four generic particulate control devices types discussed in this report.

### *Wet Scrubbers*

.13 In a wet scrubber, liquid is sprayed into the flue gas stream and adheres to the particulates. The moisture-laden particulates separate from the gas stream and are collected. The flue gas continues up the stack.

### *Electrostatic Precipitators (ESPs)*

.14 Electrostatic precipitation operates on the principle of electrically charging the particles in the flue gas stream as it flows between high d.c. voltage electrodes. The charged particles are deflected onto collecting electrodes from where they are dislodged by mechanical agitation (rapping) and fall into removal equipment for discharge to the ash disposal system.

.15 It is important that the gas flow through the ESP be uniform and non-turbulent, and that temperatures above dew point be maintained in the ESP in order to prevent corrosion.

.16 Electrical resistivity of the particles to be collected determines the physical configuration and voltage of the electrical system. Potential for sparking creates a fire hazard, particularly if carbonaceous or combustible materials are entrained in the gas stream.

.17 An electrostatic precipitator is essentially a large box containing parallel rows of collecting plates (surface) and discharge electrodes spaced to create a series of passages for the flue gas to flow through.

.18 A large voltage (40 kW) is applied to the discharge electrode and a corona discharge occurs between the discharge electrode and the grounded collecting surface.

.19 Ash particles become electrically charged and adhere to the collecting surfaces.

.20 The collecting surfaces are rapped periodically to dislodge the collected ash which is retained in hoppers in the base of the precipitator.

.21 Flue gas velocities are limited to about 1.5 metres per second to avoid re-entrainment of the ash as it is dislodged from the collecting surfaces.

.22 Precipitator performance is dependent upon the "electrical resistivity" characteristic of the ash. This characteristic is fuel specific.

.23 Reductions in performance can be compensated for by increasing the size of the precipitator; but, eventually a fabric filter would probably be an economic choice if 99.5 percent removal efficiency or better were required.

.24 Where boilers have been switched from high to low sulphur fuels it is often more economical to modify the electrical resistivity characteristic of the ash by injecting very small amounts of sulphur trioxide gas into the flue gas. This modifies the surface chemistry of the ash particle and achieves an electrical resistivity in the ideal range.

.25 Forty-year life is practical for a precipitator though major maintenance will be required periodically to replace electrical insulators and to ensure correct alignment of discharge electrodes and collecting surfaces.

.26 This technology is by far the most widely used on large utility boilers.

*Fabric Filters*

.27 Fabric filters operate by sieving material through a mesh, so that entrained particles larger than the openings in the mesh are retained and clean gas is permitted to pass. When the particles retained on the upstream side of a filter gradually accumulate, they form a filter-cake which itself, up to a point, augments filtration.

.28 After a certain degree of cake formation, gas flow is obstructed by the cake and pressure drop across the filter increases. When differential pressure sensors indicate that the pressure drop has reached a set level, gas flow to that section of the baghouse is cut off, and the fabric filter is cleaned by sending a pulse of compressed air in the reverse direction to normal gas flow or by mechanical agitation so that the cake drops into collection hoppers for discharge to the ash removal system.

.29 Fabric filters are not used to collect corrosive, wet or sticky particles nor condensibles such as tars and oils which would impair collection efficiencies of filter materials.

.30 Selection of fabric filter material is an important factor in optimization of the particulate abatement equipment along with the gas-to-cloth ratio. The lower the ratio, the more efficient the filter, but the greater the cost.

.31 Typical gas velocities through baghouses are less than 0.1m/s which accounts for the large physical size and high space requirement associated with this type of particulate control device.

.32 The application of fabric filter technology to utility boiler applications is relatively recent due to the difficulty of finding a filter material which is both flexible and able to withstand the flue gas temperatures. The development of a Teflon coated fibreglass material solved this problem.

.33 High removal efficiency of better than 99.7 percent and clear stack plumes are usual for this technology. Removal efficiency is insensitive to the ash concentration in the flue gas.

.34 Filter bags are compartmentalised in groups. It is not unusual for individual bags to fail and be replaced or sealed off. All the filter bags would normally be replaced every two to five years, depending upon how heavily they are used and the abrasiveness of the ash. Replacement of filter bags is staggered, so that a few bags would be replaced each month.

.35 Operating costs are usually higher for a fabric filter than an electrostatic precipitator due to the bag replacement costs and the additional electric power requirement to overcome the larger pressure drop that occurs across a fabric filter.

.36 Since fabric filters have similar structures and operate in similar flue gas conditions to an electrostatic precipitator, they are also expected to achieve a 40-year operating life, though at a cost of fairly heavy periodic maintenance.

## B-3-3 Nitrogen Oxides Reduction

*General*

.1 Oxides of nitrogen ($N0_x$) are formed as a result of the chemical combination of nitrogen and oxygen which occurs during combustion.

.2 The nitrogen for this chemical reaction comes from both the air and fuel. Figure B-3-2 identifies elemental nitrogen content of various fuels.

.3 Oxides of nitrogen have long been recognized as causes of smog and ground level ozone.

.4 Oxides of nitrogen are increasingly being recognized as playing a significant role in the acid rain phenomenon. Acid gas contributes to lake acidification and forest damage through long range transport and deposition of nitrates.

.5 Flue gas is largely carbon dioxide, nitrogen and water. Oxides of nitrogen typically represent 0.035 percent to 0.07 percent by volume of the flue gas at Ontario Hydro's existing stations.

.6 Oxides of nitrogen are generally reported as nitric oxide (NO) in grams/kWh or parts per million by volume (ppm). NO is the dominant oxide of nitrogen in the flue gas.

### *$NO_x$ Control Processes*

.7 The production of nitrogen oxides during the combustion of fossil fuels is a function of the "fuel bound nitrogen" and the flame temperature. Nitrogen oxide emissions can therefore be minimized by choice of fuel and by limiting flame temperatures to less than 1500°C, i.e., by controlling the combustion process.

.8 In addition, processes which chemically treat the flue gas to remove oxides of nitrogen can also be used. Chemical processes rely on treating the flue gas with nitrogen based chemicals such as ammonia or urea. Under the right conditions these chemicals reduce the oxides of nitrogen to elemental nitrogen and water vapour.

.9 Four approaches to nitrogen oxide emission control are described:

- combustion controls,
- steam/water injection,
- selective non-catalytic reduction (ammonia/urea), and
- selective catalytic reduction.

### *Combustion Controls*

.10 Over the last 10 or 12 years all major boiler manufacturers have developed combustion controls to minimize nitrogen oxide emissions.

.11 The approach has been to limit flame temperature by controlling the air distribution to the burning fuel. This may be achieved by stratifying the air supply through each individual burner and/or introducing part of the combustion air supply at different locations in the boiler.

.12 Combustion control is the most economical approach to nitrogen oxide control. It will be implemented even if further reductions through chemical treatment are required.

### *Steam/Water Injection*

.13 In the case of gas or oil-fired CTUs, steam or water can be injected through the burners to limit flame temperature, resulting in significant reductions in nitrogen oxide emissions.

.14 Steam or water injection is not suited for use with boilers.

### *Ammonia/Urea Injection*

.15 Some American utilities are injecting ammonia or urea into boilers to convert oxides of nitrogen into elemental nitrogen and water vapour.

.16 Significant reductions in nitrogen oxide emissions can be achieved using this approach with boilers as small as 10 to 30 MW.

### *Selective Catalytic Reduction*

.17 Anhydrous ammonia is introduced into the flue gas between the furnace and the electrostatic precipitator. The flue gas temperature is in the range of 315°C to 400°C. The resulting mixture is passed through a catalyst bed of vanadium, platinum or titanium compounds. The ammonia reduces the nitrogen oxides to nitrogen and water in the presence of the catalyst. The used catalyst is the only waste that requires disposal as a result of this process.

.18 This is the only commercially available post-combustion nitrogen oxide control process.

.19 The process is used commercially in Japan and Western Europe in coal-fuelled boilers. In the United States there is some limited experience with gas-fuelled boilers but only pilot plant experience with coal-fuelled applications.

.20 The catalyst is costly and must be added or replaced periodically because of erosion and poisoning.

.21 Up to 80 percent reduction of nitrogen oxide emissions can be achieved using this process.

.22 Given the complexity and cost of SCR it would be the technology of last resort to be applied to generating units.

## B-3-4 Acid Gas Reduction (other than $NO_x$)

### *General*

.1 Figure B-3-2 also shows typical elemental sulphur content for various fuels.

.2 Sulphur which is not removed before combustion burns to produce sulphur dioxide ($SO_2$).

.3 Fuels such as MSW may also produce other acidic constituents such as hydrogen chloride.

.4 Tall stacks reduce ground level concentrations of acid gases in the local environment by diluting the flue gases in the atmosphere. However, tall stacks do not solve long range acid gas problems.

.5 The chemical conversion of sulphur dioxide to sulphate, and its deposition at considerable distances from the point of emission have a deleterious effect on terrestrial and aquatic ecosystems.

.6 Any process which removes sulphur dioxide from the flue gas is known as flue gas desulphurization or FGD and some of the techniques used are also suitable to remove hydrogen chloride.

*FGD Processes*

.7 Since sulphur dioxide is acidic, FGD processes use alkaline materials called reagents to absorb and remove the sulphur dioxide from the flue gas.

.8 FGD equipment tend to be large and expensive since large volumes of flue gas containing low concentrations of $S0_2$ must be treated.

.9 Large quantities of product can result from the reaction of the sulphur dioxide or hydrochloric acid and the reagent. The product may be useful or may be a waste. In the case of MSW can be used to help bind bottom and fly-ash in landfills and thereby resist water leaching.

.10 Three FGD processes are described in the Thermal Cost Review – limestone slurry, limestone dual alkali and lime spray dryer.

.11 Each of these processes reduces $S0_2$ emissions; however, each has the effect of reducing net station output and each creates residue which must be disposed of.

.12 FGD equipment adds to capital and operating costs, a factor which has an increased significance in the case of relatively small generating stations.

.13 FGD is not required when low sulphur fuels such as biomass and peat are burned to produce electricity.

.14 Some form of gas scrubbing system, similar to the FGD processes mentioned here, would likely be required to remove acid gases such as hydrochloric acid (HCl) from the flue gas resulting from the combustion of MSW.

### B-3-5 Metal and Toxin Controls

.1 Many gaseous toxins carried in the flue gas may be condensed in scrubbers and then collected in a baghouse. Dry scrubbing with bag filters can yield a dioxin removal rate of greater than 99 percent. (Carlsson, 1988)

.2 Many metals in the flue gas (e.g., zinc, lead and cadmium) may be condensed in scrubbers or collected in either electrostatic precipitators or fabric filter baghouses (98 percent efficiency). (Bouscaren, 1988)

.3 Mercury tends to occur as a vapour. Chow et al reviewed available data regarding mercury removal. It was suggested that conventional wet FGD, combined with conventional particulate removal (e.g., cold-site ESP) can remove approximately 60 to 80 percent of the mercury present in flue gas. Removals as high as 95 percent were reported. (Chow et al, 1991)

## B-4 Fuel Transportation

### B-4-1 General

.1 Transportation is a major consideration since large quantities of fuel are consumed to produce electricity.

.2 Biomass, peat and MSW are indigenous to Ontario.

.3 They have relatively low energy content and high moisture content. They are generally suitable for local situations which minimize transportation distances and costs.

.4 The delivered price of fuel is sensitive to the distance from the source of the fuel to the generating station.

.5 An appropriate transportation infrastructure is required to deliver any of the fuels to the generating station at the lowest cost consistent with supply security and flexibility.

.6 Not all systems are practical for transporting all fuels.

### B-4-2 Pipeline Transportation

.1 Pipelines can be used to carry natural gas or oil over long distances. They can also transport coal/oil or coal/water slurries. Technology is being developed to transport peat/water slurries over relatively short distances.

.2 Pipelines are reliable in that they suffer infrequent failures. Short term flexibility is limited. Since pipelines run at high capacity factors new pipelines may be required to meet changing needs. Lead time is required to get approvals and to install new pipelines.

.3 The construction of interprovincial pipelines dedicated strictly to Hydro's use is unlikely to be cost effective.

### B-4-3 Rail Transportation

.1 Rail transportation is used mainly for coal and oil products. It could also be used for liquidified or compressed natural gas. Cost considerations may mitigate against rail transport of low energy fuels although rail transport has been considered for the shipment of MSW and biomass.

.2 Rail transportation is characterized by limited flexibility in pickup and delivery points, and in Canada, limited competition. Rail transportation in combination with storage at generating stations is reliable.

.3 Special train cars are required for each fuel in order to minimize costs.

.4 Cost-savings have been achieved by utilizing "unit trains", large dedicated trains which shuttle continuously from unloading dock or mine site to destination.

### B-4-4 Water Transportation

.1 At present Ontario Hydro uses water transportation only in conjunction with rail transportation for coal and oil delivery.

.2 Water transportation includes coal barges (used to transport some eastern US bituminous coals), Great Lakes ships (used for coal shipments), and ocean vessels (used to deliver residual oil).

.3 Dock facilities are required for loading and unloading. Storage facilities may also be required. Large coal terminal facilities exist throughout the Great Lakes region.

.4 Water transportation on the Great Lakes, is limited to the ice-free season which is typically from April to December.

.5 Water transportation is expected to have little if any application with respect to biomass or other alternative fuels.

### B-4-5 Road Transportation

.1 Trucks are used for short distance haulage of most fuels.

.2 Trucks are very flexible as to pickup and delivery points, but, they are relatively expensive to operate.

.3 Trucks are less practical for haulage of large quantities of fossil fuels over long distances; however, they may be suited to delivery of biomass and other alternative fuels to relatively close generating stations.

### B-4-6 No Transportation

.1 No transportation is required for a mine-mouth generating facility. The fuel is mined and fed directly to an on-site generating station.

.2 Mine-mouth generation is economic only when the costs of electricity transmission do not override savings in fuel transportation.

.3 To date mine-mouth generation has not been used in Ontario; but, it can be the basis for non-utility and alternative generation.

## B-5 References

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